

Transmission pricing discussion paper

Version 2: initial draft of some sections

April 2011

Note: This paper includes initial drafts of some sections. The table provided in the 'Executive Summary' section below summarises the progress on each section and provides guidance to TPAG members for reviewing the paper.

Reviewers should note that:

Some sections are yet to be drafted and some require further discussion with TPAG.

There is repetition through some sections of the paper, which will be dealt with in subsequent drafts.

Sections 4 and 5 need to be tightened and more closely tied back to the statutory objective.

Note: This paper has been prepared for discussion with TPAG. Content should not be interpreted as representing the views or policy of the Electricity Authority or of TPAG.

Executive summary

Overview of progress on sections

	Section	Progress
1	Introduction	These drafts were provided to TPAG meeting 4 (25 March 2011). Some minor amendments have been made to these sections, but they will require further review when the remaining sections are completed.
2	Background	
3	Summary of earlier stages of the review	
4	Analysis framework	<p>For discussion at TPAG meeting 5, 8 April</p> <p>This is based on the analysis framework agreed at TPAG meeting, but has been updated with the TPAG conclusions on the impact of regulatory change on work undertaken to date.</p> <p>Note: both sections 4 and 5 need to be tightened and possibly amalgamated and more closely tied back to the statutory objective.</p>
5	Approach to assessment	<p>For discussion at TPAG meeting 5, 8 April</p> <p>This is based on the 'progress report – pathway through the options' presentation that was discussed at TPAG meeting 4, 25 March 2011.</p>
6	Overview of options	This is the overview of options provided to TPAG meeting 1 (16 Feb 2010). It will require review for consistency with other sections as they are completed.
7	Location-based price signals	This is based on the 'GEM analysis paper' provided to TPAG meeting 3 and subsequently amended and agreed at meeting 4, although there are outstanding comments to be noted from one member not present at meeting 4.
8	Assessing options for HVDC charges	<p>For discussion at TPAG meeting 5, 8 April</p> <p>This section is newly included and is based on previous discussions and presentations at TPAG meetings.</p>
9	Assessing options for deferring reliability investments	To be drafted
10	Assessing other options	To be drafted
11	Preferred option for TPM	To be drafted
12	Conclusion	To be drafted
	Appendices	<p>For discussion at TPAG meeting 5, 8 April</p> <p>The appendix on the impact of HVDC cost allocation on investment in new generation is newly included in the paper.</p>

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Glossary of abbreviations and terms

[insert text]

[insert text]

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1 Introduction

1.1 The Transmission Pricing Advisory Group (TPAG)

- 1.1.1 The Electricity Authority (Authority) is continuing the Transmission Pricing Review (Review) initiated by the Electricity Commission (Commission) in early 2009 to undertake a wide-ranging review of options for the allocation methodology for transmission costs. The Review is a multi-stage project, involving technical and economic analysis and stakeholder consultation.
- 1.1.2 The Authority has formed the Transmission Pricing Advisory Group (TPAG) to assist it in this, the third stage of the Review. The TPAG is tasked with providing independent advice to the Authority on the development of a preferred Transmission Pricing Methodology (TPM).
- 1.1.3 The TPAG members were appointed by the Authority following a call for nominations in January 2011. The membership is set out in Table 1.

Table 1 TPAG membership

Member	Nominating body
Graham Scott (chairperson)	-
John Clarke	Transpower
Glenn Sullivan	Fonterra
Bruce Girdwood	Vector
Ray Deacon	RTANZ
John Woods	Contact
Bob Weir	Genesis
Guy Waipara	Meridian
Peter Calderwood	Trustpower
David Reeve	Mighty River Power

- 1.1.4 The TPAG has been established in accordance with the Electricity Industry Act 2010 (Act) and the Authority's Charter about Advisory Groups (Charter).¹ The TPAG terms of reference² set out the role of TPAG, the scope of the advice sought, and further details of TPAG's governance and operations.

1.2 Purpose

- 1.2.1 A key aspect of the TPAG role is to publish a discussion paper for consultation with interested parties, which provides, with supporting analysis, a preferred TPM option and associated guidelines for the development of a TPM by Transpower. This paper is the TPAG's Discussion Paper. Following its consideration of submissions, the TPAG is required to make its recommendations to the Authority Board. If TPAG's recommendation is for an alternative methodology and the recommendation is

¹ Available at: <http://www.ea.govt.nz/document/12289/download/our-work/advisory-working-groups/tpag/>

² Available at <http://www.ea.govt.nz/document/12747/download/our-work/advisory-working-groups/tpag/>

accepted by the Authority Board, the Authority will publish an Issues Paper and draft guidelines for the TPM.

- 1.2.2 Accordingly, the purpose of this TPAG Discussion Paper is to invite submissions on TPAG's analysis and recommendations for transmission pricing. The following sections of the paper:
- (a) set out the (new) regulatory context for the Transmission Pricing Review;
 - (b) provide a high level summary of submissions received on the Commission's 'Transmission Pricing Review: Stage 2 Options' consultation paper, and on further analysis completed since that time;
 - (c) describe the key TPM options to be considered, and the analysis framework to be applied when assessing those options;
 - (d) set out the TPAG's preferred TPM option for the allocation of transmission costs including proposed guidelines for Transpower in developing a TPM, and the supporting analysis; and
 - (e) summarise the next steps in the Review.

1.3 Submissions

1.3.1 This consultation paper is published by TPAG. Although TPAG will be responsible for considering the submissions, the Authority will receive submissions on TPAG's behalf.

1.3.2 The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with "TPAG Transmission Pricing Discussion Paper" in the subject line.

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

Submissions
TPAG Chair
c/- Electricity Authority
PO Box 10041
Wellington 6143

or

Submissions
TPAG Chair
c/-Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860
Fax: 0-4-460 8879

- 1.3.4 Submissions should be received by 5.00 pm on [date]. Please note that late submissions are unlikely to be considered.
- 1.3.5 The Authority, on behalf of TPAG, 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.
- 1.3.6 Your submission is likely to be made available to the general public on the Authority'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 TPAG on a confidential basis. However, all information provided to TPAG is subject to the Official Information Act 1982.

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2 Background

2.1 Transmission pricing in New Zealand

- 2.1.1 Transpower's transmission network is a natural monopoly and its revenue requirement is regulated by the Commerce Commission. The TPM determines how Transpower's total revenue is allocated between, and recovered from, its customers. Transpower develops the TPM in accordance with Part 12 of the Electricity Industry Participant Code (Code)(refer Section 2.3 below). The Authority 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. 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.
- 2.1.3 The current TPM is based – with some refinements – on the TPM that was developed by Transpower and first applicable from 1 April 1999. 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 South Island generators only. The current TPM took effect on 1 April 2008 and is comprised of these three charges, but has introduced further refinements. These include a change to the allocation of interconnection charges according to the Regional Coincident Peak Demand (RCPD), and a deeper definition of connection assets.

2.2 The transmission pricing review

- 2.2.1 During the development of the current 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.
- 2.2.2 The rationale at the time was that nodal pricing, the approval of transmission investment under the 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. This proved to be a controversial decision and, following the determination of the TPM, parties requested that the Commission undertake a further review of the HVDC charge. 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.
- 2.2.3 Against this background the Commission initiated the Transmission Pricing Review (Review) in early 2009 to undertake a wide-ranging review of options for the allocation methodology for transmission costs. The Authority is continuing with the Review.

2.3 Regulatory context for the Review

- 2.3.1 The Government established the Authority in 2010 under the Electricity Industry Act 2010 (the Act), to oversee the governance and operation of New Zealand's electricity market. The Authority succeeded the Electricity Commission on 1 November 2010, as one of a number of sector changes introduced under the Act. The Authority is an independent Crown Entity.
- 2.3.2 The objective of the Authority, as prescribed in Section 15 of the Act, is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.
- 2.3.3 The Electricity Industry Participation Code 2010 (Code³) and the Electricity Industry (Enforcement) Regulations 2010 (Regulations) came into force on 1 November 2010. The Authority is required to make and administer the Code and to monitor compliance with the Act, Regulations, and the Code. Although operating as an independent regulator, the Authority is required to have regard to Government Policy Statements presented in Parliament by the Minister of Energy and Resources. The Authority must also undertake reviews of specific electricity industry issues at the request of the Minister.
- 2.3.4 The Authority has three foundation documents which make key strategic statements as to how the Authority will approach its decision making and undertake its duties under the Act. These are summarised in (Table 2), and are available in full from the Authority's website⁴. These documents are of relevance to the Review, and to the TPAG's role. In particular, the assessment framework described in Section 4 of this paper draws heavily on these, and the TPAG work programme also acknowledges the Authority's policies regarding consultation and progressing Code amendments.

Table 2 The Authority's foundation documents

Foundation document	Purpose and content
Interpretation of the Authority's statutory objective	<p>Section 15 of the Electricity Industry Act 2010 (Act) provides the Authority with a single statutory objective.</p> <p><i>To promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers</i></p> <p>The Interpretation of the Authority's statutory objective clarifies how the Authority interprets its statutory objective, will assist the Board to make consistent decisions, and will assist staff and advisory groups to develop Code amendments and market facilitation measures for the Board's consideration.</p>

³ The Code is largely based on the Electricity Governance Rules 2003, the Electricity Governance (Security of Supply) Regulations 2008 and the Electricity Governance (Connection of Distributed Generation) Regulations 2007.

⁴ Available from <http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/>

Foundation document	Purpose and content
Consultation Charter	<p>The Act requires the Authority to develop, issue, and make publicly available a consultation charter. This consultation charter must include guidelines, not inconsistent with the Act, relating to the processes for:</p> <ul style="list-style-type: none"> (a) amending the Code; and (b) consulting on proposed amendments to the Code. <p>For the sake of clarity, the Authority has divided the consultation charter into two parts:</p> <p>Part 1 relates to processes for amending the Code; and</p> <ul style="list-style-type: none"> (c) Part 2 relates to processes for consulting on proposed amendments to the Code. <p>A key aspect of the Consultation Charter is the set of Code Amendment Principles which are to be applied when considering options for amending the Code.</p>
Charter about Advisory Groups	<p>The Act requires the Authority to establish one or more advisory groups⁵ to provide independent advice to the Authority on the development of the Code and on market facilitation.</p> <p>The Act requires the Authority to make, and make publicly available, a charter on:</p> <ul style="list-style-type: none"> how it will establish and interact with the advisory groups; and (d) when and how it will consult advisory groups on material changes to the Code; and (e) how advisory groups must operate, including provisions concerning procedure.

2.3.5 The Code⁶ provides that the purpose of the TPM is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs of Transpower's services are allocated in accordance with the pricing principles (clause 12.79) and provisions on their interpretation and application (clause 12.80).

2.3.6 Thus the regulatory framework for the development of the guidelines and the TPM consists of:

- (a) relevant provisions of the Act, where the new statutory objective is of particular relevance;
- (b) specific provisions of the Code (which includes the pricing principles as set out in the clause 12.79 of the Code (pricing principles) and provisions on their interpretation and application); and
- (c) potentially statements of government policy.

2.3.7 Furthermore, by virtue of the fact that the TPM is a schedule to the Code (Schedule 12.4 of part 12), any proposal to amend the existing TPM must ultimately be progressed as a Code amendment. Thus the provisions in the Act relating to Code amendments generally, and the Authority's foundation documents (Table 2 above), specifically the Code Amendment Principles are also relevant to the TPM decision framework.

2.3.8 It is important to note, however, that the establishment of the Authority with a new statutory objective has led to a reconsideration of the decision framework that underpinned previous decisions about the TPM. As part of a separate Review workstream, the Authority has reviewed the ongoing

⁵ The Act also requires the Authority to appoint an advisory group called the Security and Reliability Council to provide independent advice to the Authority on the performance of the electricity system and the system operator and reliability of supply issues.

⁶ Clause 12.78 to 12.79.

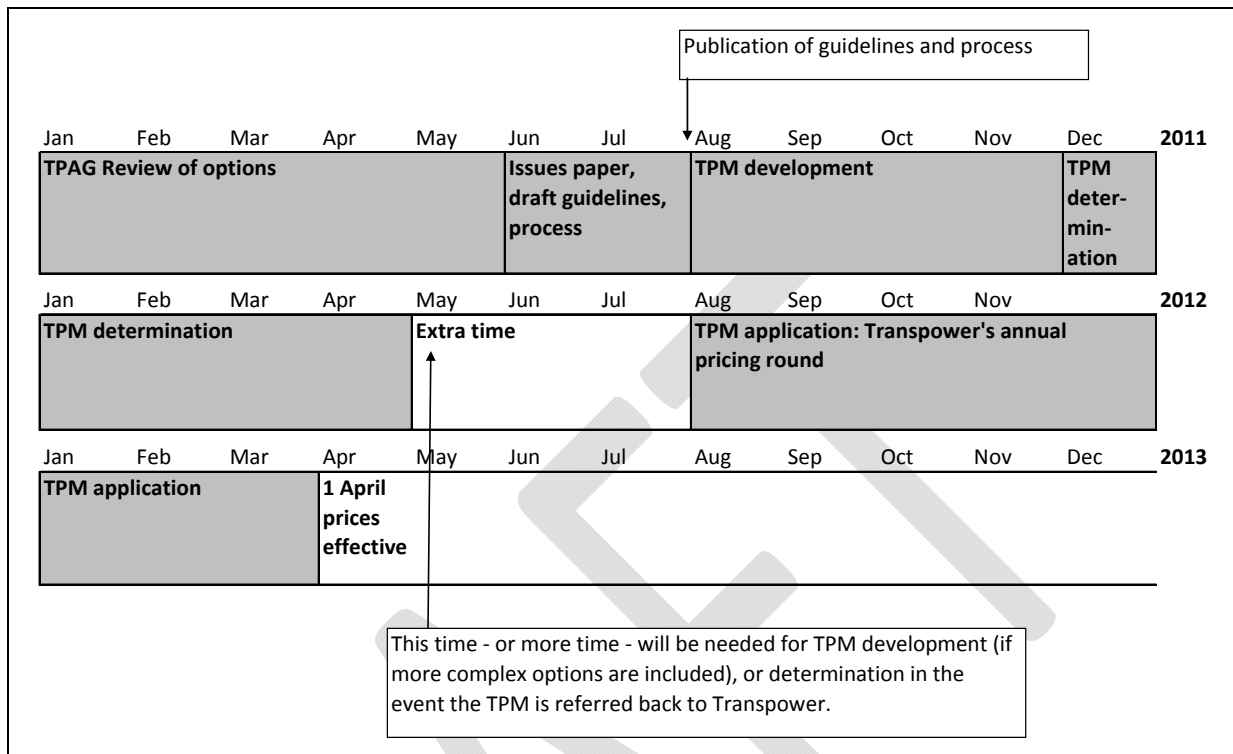
relevance of the pricing principles and is proposing an amendment to the Code. Initial analysis supports the contention that the interface between the statutory objective, the guidelines and the pricing principles is complex and unwieldy and, combined with the ongoing lack of consensus around the pricing principles, is a demonstrable regulatory failure. The Authority's proposed approach is to remove the pricing principles and the related interpretation clauses (clauses 12.79 and 12.80) from the Code. In February 2011 it initiated a Code amendment process in accordance with section 39 of the Act. The outcome of this process will need to be accommodated into the Review and the work of the TPAG in developing its preferred TPM option and guidelines.

2.4 Review process and timetable

- 2.4.1 The Authority has continued with the Review initiated by the Commission in April 2009. Drawing on the regulatory context summarised above, this section describes the key steps in the Review from this point onwards, together with an indicative timetable for implementation. Earlier stages of the Review are summarised in Section 3 of this paper (below).
- 2.4.2 At the request of senior industry stakeholders, the TPAG has been set up to develop and recommend its preferred TPM option and guidelines to the Authority Board, following a consultative process (the purpose of this Discussion Paper). The TPAG is undertaking its work as a matter of urgency, and, although this is an additional step in the Review process, the intention is to maintain a timeline for the Review that would enable implementation of any changes to the TPM for the pricing year starting 1 April 2013.
- 2.4.3 The timeline is shown in Figure 1 below. There are three phases to this work:
- (a) the TPAG review of options;
 - (b) the Code-prescribed processes (Publication of the Issues paper, draft guidelines and process, publication of guidelines and process, TPM development and TPM determination) that will follow if the Authority determines that a new TPM is justified; and
 - (c) the application of a TPM (Transpower's annual pricing round).

[note that the timeline shown in the figure below will need to be updated to reflect the delay in TPAG's programme. The implications of this will be considered by the Authority Board at its meeting on 6 April 2011]

Figure 1 Transmission Pricing Review – key steps and indicative timeline [to be updated]



2.4.4 The time required for the Code-prescribed processes and the application of a new TPM by Transpower places time constraints on the indicative timeline described above. Table 3 gives approximate timeframes for the Code-prescribed processes for development and determination of the TPM and the time it takes to apply a TPM. It also includes estimated timeframes for implementation – the time Transpower will require for software and process development and testing.

2.4.5 The application of the TPM is an annual process. For prices to be effective from 1 April in any given year, Transpower begins its pricing process (including calculating and auditing prices) by August of the preceding year. Transmission agreements require Transpower to provide prices by 31 December of the preceding year for application on 1 April. Transpower seeks to provide prices before this date to assist participants.

Table 3 Estimate time required for Code-prescribed processes

Stage	Detail	Relevant Code provisions	Approx Timeframe
Issues Paper, draft Guidelines and Process	Issues Paper and draft Guidelines and Process, for consultation	12.81 to 12.83	2 months

Stage	Detail	Relevant Code provisions	Approx Timeframe
TPM development	Authority publishes Guidelines and Process and requests new TPM. Transpower submits a TPM within 90 days of request, including indicative prices.	12.88,12.89	4 months <i>Note: Transpower may require more time for TPM development</i>
TPM determination	Authority: <ul style="list-style-type: none"> • may decline to consider the TPM • approves or refers back or amends • publishes proposed TPM for consultation • makes determination on TPM • TPM gazetted, becomes a schedule to the Code 	12.90 to 12.94	4 -5 months <i>Note: More time may be needed if the TPM is referred back to Transpower</i>
Transpower implementation (Not a Code-prescribed process)	This is the time Transpower requires for implementing a new TPM and will depend on the complexity of the preferred option. Transpower has provided initial estimates for some options (refer Section 3 for a brief description of each). Some examples are given.	Postage stamp HVDC, 5 months HVDC charge to MWh, 6 months Flow tracing , 18 months Bespoke pricing, 12 months	
TPM application	Transpower develops, audits and publishes prices.	12.96 to 12.101	Start Aug of year preceding pricing year

[Note: As indicated in the Work Plan previously presented to TPAG, if there are to be changes to the TPM in place for April 2013, the Authority must publish an Issues Paper with draft guidelines and process by June/July 2011. Final guidelines and process must also be published by August 2011, and the TPM must be submitted to the Authority by December 2011. However, this timeframe assumes that:

- the TPM determination is straightforward and does not require referral back to Transpower;
- any changes do not require more substantive development by Transpower than the 3 months extra time built into the timeframe; and/or
- Transpower is willing to undertake some implementation in parallel to other processes, or is able to reduce implementation times.]

2.4.6 There are a number of related and parallel work streams which may also impact on the Review process, depending on the outputs of those workstreams and their relevance to the Review findings. In particular:

(a) **Code amendment proposal for the regulatory framework for transmission pricing.** The Authority has published a proposed Code amendment consultation paper on the regulatory framework for transmission pricing, specifically the pricing principles. [update as required once timetable/implications are clearer] TPAG [has published] its discussion paper in advance of a final decision on the proposed Code amendment, in the knowledge that the underlying analysis will need to align with the eventual regulatory framework. In the event that the analysis turns out to have been based on an option from the Code amendment proposal not used in the analysis, the analysis would need to be updated to reflect the actual regulatory position. TPAG analysis in support of its recommendations on a preferred TPM must reflect the outcome of the Code amendment proposal process. The Authority expects to make a final decision on this Code amendment proposal in April 2011.

(b) **The Authority's locational hedging project.** This project expects to publish a consultation paper on the Code development for the introduction of an inter-island Financial Transmission Right (FTR) in [April 2011]. Participants have indicated that having an understanding of the preferred options for transmission pricing is a significant issue for understanding the implications of a locational hedging proposal. This is particularly the case for the pricing for the HVDC link. [consider also noting implementation/transition implications between this and TPM]

The Act requires that the Electricity Authority addresses the locational price risk management issue by November 2011⁷. The development of the locational price risk is also linked to the proposed introduction of scarcity pricing, discussed in the next bullet.

(c) **The Authority's scarcity pricing project.** This project ... [to be completed].

(c) **The Commerce Commission's Transmission Investment Input Methodology.**

The final input methodology determinations for Transpower, lines companies and other relevant sectors were published on 23 December 2010⁸.

In addition to these input methodologies, the Commerce Commission is also required to determine an input methodology for Transpower's capital expenditure proposals (Capex IM). This input methodology will include the grid investment approval process and as part of this, the process for consideration of transmission alternatives. The Capex IM must be determined no later than 1 November 2011, but the Minister of Commerce may, on the written request of the Commission, extend the deadline once by a period of up to three months. The Commission has released its notice of intention to advise that it has begun work on the Capex IM and its initial views on Capex IM.

⁷ There is an ability for the Authority to postpone addressing these issues within the timeframe outlined above. Section 42 of the Act provides that the Authority can provide a report to the Minister if any of the new matters required to be addressed (including locational price risk management and scarcity pricing) are not addressed within the prescribed timeframes. According to section 42(3), this report must identify those matters, explain why they have not been addressed, suggest alternative methods to address them and set out if, when and how the Authority proposes to address them. The Authority is however working towards meeting the timeframes set out in the Act.

⁸ These determinations are subject to appeal.

3 Summary of earlier stages of the Review

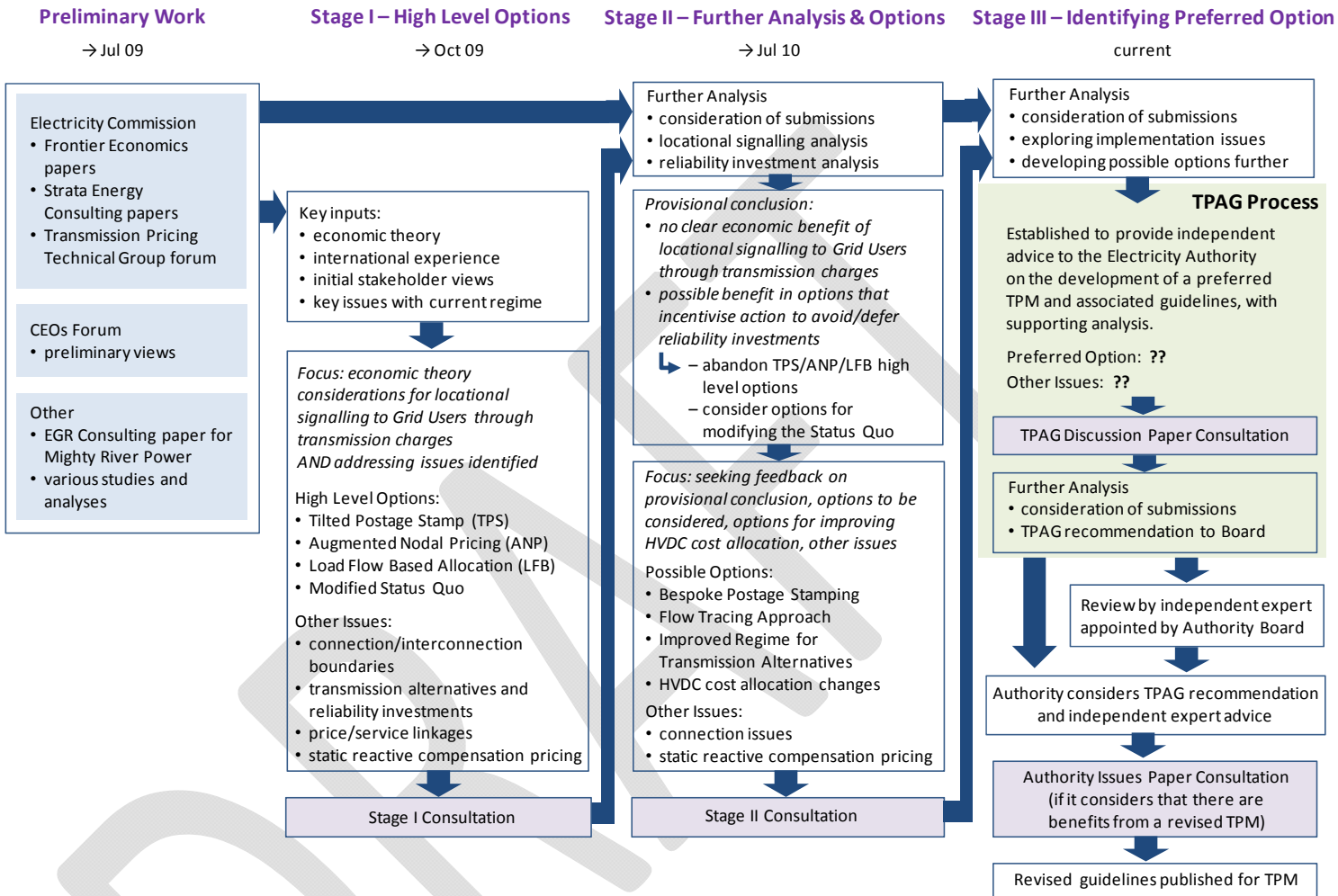
- 3.1.1 This section provides a high level summary of the analysis and outcomes from earlier stages of the Review. A pictorial representation of the Review is set out in the following figure, and described in more detail below.
- 3.1.2 The Commission initiated the Review of the methodology for allocating transmission costs in April 2009. Following preliminary work on transmission pricing by the Commission, the Commission published a High Level Options Paper for consultation (Stage I) in October 2009. It considered the submissions received and undertook further analysis, before publishing a second consultation paper (Stage II) in July 2010. The Commission's specially formed Transmission Pricing Technical Group (TPTG) provided advice during both these stages, as did its advisers, Frontier Economics and Strata Energy Consulting. Other stakeholders engaged their own advisers and provided input to the Review (for instance, the CEOs Forum engaged NERA, and MEUG and Rio Tinto engaged NZIER).
- 3.1.3 The Authority came into being on 1 November 2010 and continued with the Review, now under the jurisdiction of the Electricity Industry Act. Following the establishment of the Authority and in light of submissions from the second consultation paper, it developed a revised plan. It also established the TPAG to assist it in this third stage of the Review.

3.2 Preliminary work

- 3.2.1 The Commission and a number of stakeholders undertook analysis and engaged advisers in the lead up to the Review's first formal consultation (Stage I). For the purposes of this Roadmap, this has been grouped together as "Preliminary Work", although some of it relates to the period before the Review was initiated, and some of it continued in parallel with Stage I of the Review. Of particular note:
- 3.2.2 **Commission work:** The Commission announced the Review in April 2009, established the Review project and work programme, and formed the TPTG made up of technical specialists nominated by interested parties. As well as drawing on earlier analysis and reports, the Commission engaged Frontier Economics to provide advice, including papers on the theory of efficient pricing of electricity transmission services (Jul09) and an international review of transmission pricing (Jul09). The Commission also engaged Strata Energy Consulting who prepared a summary of transmission pricing arrangements in NZ 1998 to 2008 (Jun09) and a report on the transmission pricing issues identified in the TPTG forum (Aug09). The Frontier and Strata papers were key inputs to the Stage I consultation, and are discussed further below.
- 3.2.3 **EGR Consulting Report:** Mighty River Power had earlier commissioned Dr Grant Read to provide a report on locational transmission pricing (Feb07). The report proposed a "Tilted Postage Stamp" (TPS) pricing regime for transmission system cost recovery in New Zealand. It was motivated by the belief that, given the existing approach to transmission system planning and cost recovery in New Zealand, the combination of nodal spot price differentials with a "Postage Stamp" (PS) cost recovery regime is unlikely to reflect the full extent of locational variations in the long run cost of servicing load and/or generation growth.
- 3.2.4 **CEOs Forum input:** NERA was engaged by the NZ Electricity Industry Steering Group (established by the CEOs Forum) to explore ways in which to improve the efficiency of electricity transmission pricing arrangements in the NZ market. The CEOs Forum provided preliminary views to the Commission during this time, with the formal NERA Report submitted shortly after the Stage I consultation process.

Figure 2 Overview of the transmission pricing review

Transmission Pricing Review – Overview



3.3 Stage I – High Level Options (to October 2009 consultation)

3.3.1 The preliminary work described in the previous section provided some of the key inputs to the Commission’s work in establishing the high level options to consider and the key issues to also be addressed in the Review process, i.e:

- economic theory;
- international experience;
- stakeholder views; and
- key issues with current regime.

3.3.2 It also helped to frame the focus for the first stage of the Review:

- economic theory considerations in particular whether there was sufficient justification to consider enhanced locational signalling in addition to that provided by nodal pricing, deep connection and the grid investment test; and
- addressing the key issues identified.

3.3.3 The Commission analysis and thinking was set out in its Stage I Consultation Paper (Oct 2009)⁹. This was drawn from the key inputs described above, and further informed by the Commission’s own analysis, feedback from the TPTG and the papers prepared by Frontier Economics (particularly its paper entitled “Identification of High Level Options and Filtering Criteria”, Sep 09).

3.3.4 The high level options included in the Stage I Consultation were:

- (a) **Status Quo** – the current transmission pricing arrangements were included as a high-level option. The stage 1 consultation paper also asked submitters if there were possible minor modifications that could be made to the current arrangements.
- (b) **Tilted Postage Stamp** – this approach is intended to provide broadly appropriate locational signals to generators and loads. Assuming the historical pattern of network flows continues into the future, it would mean imposing comparatively higher charges on generators in the South Island and loads in the North Island and lower charges on generators in the North Island and loads in the South Island.
- (c) **Augmented Nodal Pricing** – this approach seeks to directly address the deficiencies in nodal energy prices created by excessive or premature network investment; and the issue that the value of reliability is not signalled in nodal prices. Under this regime: transmission charges should be highest for those generators and loads that benefit most from excessive or premature network investment; and transmission charges should be lowest for those generators and loads that are made most worse off from excessive or premature network investment.
- (d) **Load Flow Based Allocation** – these options involve a process of network analysis to attribute costs to participant connection points based on identification of the network assets ‘used’ to convey electricity from points of injection to points of withdrawal. Load flow approaches can be based on the topology of the existing network as in Australia (cost reflective network pricing (CRNP)) or on forward-looking network development costs, as in Great Britain (investment cost related pricing (ICRP)).

3.3.5 Further to these high-level options, the Consultation paper also set out four other key issues arising in the consideration of transmission pricing during Stage I of the Review:

- the approach to setting connection charges;
- the treatment of transmission alternatives;
- linking transmission pricing with service quality; and
- static reactive power compensation.

⁹ The paper was released together with two other Commission consultation papers on related issues: ‘Scarcity Pricing and Compulsory Contracting : Options’ and Locational Price Risk Management: Options.

3.4 Stage II – Further Analysis and Options (to July 2010 consultation)

3.4.1 Nineteen parties from across the electricity sector provided submissions on the Stage I Consultation Paper, as set out in Table 4. The Commission also received final reports and analysis from the CEO Forum including analysis from Transpower, and NZIER reports on behalf of MEUG and Rio Tinto:

- (a) **CEOs Forum input:** NERA considered that many features of the existing transmission pricing arrangements were fundamentally sound, but there were some potential problems (including issues relating to LRMC signalling, the GIT, HVDC charging, and deep connection). NERA considered a number of possible options for reform including introducing further locational signals (eg through a TPS approach), modifying the HVDC charging regime, and some relatively modest amendments to connection charge arrangements.
- (b) **Transpower work:** Transpower undertook analysis at the request of the CEO Forum working group to determine whether there is an enduring grid characterisation that might support the introduction of a TPS pricing methodology and to assess the potential impact of a TPS on total costs.
- (c) **NZIER:** NZIER was commissioned to undertake work for Rio Tinto and for the Major Energy Users' Group (MEUG) as input to the CEOs Forum and to the Commission's Review. NZIER completed three reports for MEUG:
 - 'New Zealand Transmission Pricing Project – A Review of the NERA report to the Electricity Industry Steering Group'. This report was critical of NERAs analysis and of the basis for the NERA options.
 - 'Alternative Options for Transmission Pricing – Suggestions for the Review by the CEOs Forum.' This report suggested a capacity rights or arbitrageur approach for the HVDC link and a deeper connection regime for charging for new assets (also known as 'but-for').
 - Competitive Neutrality for connection of generation. This report contained a discussion about the TPM on generators decisions on where to connect.

NZIER also completed a report for Rio Tinto in the form of a letter on Capacity Rights.

Table 4 Submissions received on Stage I Consultation Paper

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

3.4.2 Views were mixed, and no clear favourite emerged from the consultation process. Some submitters supported a TPS approach, some preferred a modified status quo, and some proposed alternative

options for the Commission to consider. The Commission published an initial summary of submissions in March 2010.

3.4.3 In parallel with its consideration of submissions, the Commission:

- reconsidered the economic theory arguments for further locational signalling to generation and load to encourage co-optimisation of investment in generation, load and transmission;
- undertook significant modelling and analysis work using its Generation Expansion Modelling tools (GEM) to consider the potential benefits of further locational signalling to generation and load from the perspective of signalling in respect of future economic transmission investments;
- considered the potential benefits of deferral of future reliability transmission investments.

3.4.4 Drawing from this work and its consideration of Stage I submissions, the Commission formed two important provisional conclusions:

- there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments; and
- there appears to be a possible benefit in options that incentivise action to avoid or defer reliability-driven investments (eg through investment in generation and/or load management).

3.4.5 This analysis was set out in the Stage II Consultation Paper, and submitters' views were sought on the approach, the analysis and the Commission's provisional conclusions.

3.4.6 A key implication of the provisional conclusions, as noted in the Stage II Consultation Paper, was that there would be no merit in pursuing the three high level transmission pricing options aimed at enhancing locational signals for economically-driven transmission investments, ie Tilted Postage Stamp, Augmented Nodal Pricing, and Load Flow Based Allocation. Instead the Review should focus on options for modifying the Status Quo that might incentivise action to defer reliability-driven investments, options for HVDC charging, and addressing the other key issues identified. This framed the remainder of the Stage II work.

3.4.7 The Consultation Paper identified the following options, and sought submitters' views on each, noting that they were not mutually exclusive and could be implemented in some combination:

- (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 an LRMC approach to determining locational charges.
- (b) 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.
- (c) 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.

3.4.8 The paper also set out a number of options for HVDC charging, and sought comments on each:

- (a) status quo;

- (b) continue to charge South Island generation plant, but with an allocation proportional to generation in MWh rather than based on Historical Anytime Maximum Injection (HAMI);
- (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.

3.4.9 Finally, the paper addressed the “other issues” from the Stage I consultation, and considered two of the issues should be progressed further in the context of the Review:

- connection issues
- static reactive compensation

3.4.10 The Stage II Consultation paper, including the appendices, provides a basis for the Stage III work the Authority, and the TPAG, are now embarking on. Accordingly, the paper is included with this package of documents for the TPAG.

3.5 Stage III – Modifying the Status Quo (current)

3.5.1 Eighteen parties from across the electricity sector provided submissions on the Stage II Consultation Paper, as set out in Table 5.

Table 5 Submissions received on Stage II Consultation Paper

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

3.5.2 In very brief terms, submitters’ views on key matters set out in the Stage II paper is briefly summarised in Table 6.

Table 6 Brief summary of submissions on Stage II

Issue	Overall comment

Issue	Overall comment
Stage II analysis	<p>Submitters generally concurred with the economic theory analysis that the Commission presented in the consultation paper, agreeing that the consultation paper had identified the relevant factors in its assessment of whether nodal pricing provides adequate signals for efficient generation and load investment.</p> <p>A minority of submitters questioned the Commission’s modelling for assessing the benefits of locational signalling for economic transmission investments on the basis that the modelling was highly dependent on the input assumptions and that the use of the Generation Expansion Model (GEM) may not have been appropriate. Despite these concerns most submitters agreed with the results: that there is limited value in signalling economic transmission investments.</p> <p>Submitters challenged the analysis of the potential benefits of signalling reliability investments more strongly.</p>
Stage II Options	<p>The Commission had set out its decision not to pursue some high level options described during Stage I of the Review or previously suggested by submitters. Submitters generally supported the Commission decision not to further consider augmented nodal pricing and tilted postage stamp. Three large user representatives considered that the Commission should undertake further analysis on the ‘but-for’ approach and the capacity rights option suggested for the HVDC link.</p> <p>Submitters were divided on the benefits of the incentives for deferring reliability investments, and gave arguments both for and against the three options suggested: bespoke pricing, flow tracing and improving the transmission alternatives regime.</p>
HVDC Options	<p>The consultation paper set out costs and benefits of the existing HVDC charge and four possible options for the allocation of HVDC costs.</p> <p>The three largest South Island generators all favour postage stamping the HVDC costs. Large user representatives support further consideration of an alternative option – capacity rights, as an alternative means of allocating costs to beneficiaries. Transpower considers that there appears to be a reasonable case for retaining the charge, but allocating it based on MWh. Meridian and Todd Energy suggest allocating the charge according to flows across the link.</p> <p>Two submitters considered the existing charging is well-founded and inefficiencies are at worse, negligible, and there is no need to consider the efficiency implications of the charge any further.</p>
Further Issues	<p>Submitters commented on arrangements for independently provided connection assets. Some have suggested that, although parties should in principle be able to mutually-negotiate shared arrangements for new connection assets, in practice there is a need for intervention as a backstop. Submitters have also raised other issues in relation to connection arrangements.</p> <p>Of the three options presented in the consultation paper for the treatment of static reactive compensation, submitters generally favoured either “connection asset definition” or “kvar charging”. Transpower presented an alternative variant of kvar charging for consideration. There were strong views against both the status quo and amended status quo which rely on the terms of the Connection Code.</p>

[Note: to be completed, consistent with approved approach to addressing key issues arising in submissions, agreed by TPAG at its meeting of 25 Mar 11]

4 Analysis framework

Note – Sections 4 and 5 need to be tightened (possibly amalgamated) and more closely tied back to the statutory objective. Note also that once the EA Board has made a decision on the proposed Code amendment to remove the pricing principles there will be an exercise in tightening the description of the relationship between the statutory objective, code amendment principles, the evaluation criteria and the efficiency considerations.

4.1 Introduction

4.1.1 This section sets out the high level decision analysis framework that TPAG has used to evaluate the options for Transmission Pricing Methodology (TPM).

4.1.2 It draws on the TPAG Terms of Reference, the Electricity Authority Statutory Objective, the Transmission Pricing Principles, and the Code amendment principles, in order to derive a set of criteria for assessment and evaluation purposes.

4.2 TPAG Terms of Reference

4.2.1 The TPAG Terms of reference highlight that it has been established to:

- a) *recommend to the Authority Board, with supporting analysis, a preferred transmission pricing methodology (TPM) option, and associated guidelines, for each of the following areas:*
 - I. *the allocation of all transmission costs including those that are currently categorised as connection, interconnection and HVDC costs;*
 - II. *providing incentives for participants to take action to defer or avoid transmission investments where there are benefits in doing so; and*
 - III. *static reactive compensation;*
- b) *provide analysis and justification to support the rejection of options, including at a minimum the options considered by the Electricity Commission in its 'Transmission Pricing Review: Stage 2 Options' consultation paper and alternatives provided by submitters; and*
- c) *review and comment on submissions received on:*
 - I. *the Electricity Commission's 'Transmission Pricing Review: Stage 2 Options' consultation paper; and*
 - II. *the TPAG's discussion paper containing its preferred TPM option.*

4.2.2 These terms of reference provide guidance as to the options that need to be considered and the extent of analysis that needs to be provided in support of the group's recommendations. In particular, it identifies that TPAG needs to provide sufficient analysis of the options considered in the Stage 2 options consultation paper to either reject or develop preferences. The options considered in the Stage 2 options consultation paper include:

- (a) The high level options first canvassed in the October 2009 consultation paper and explored further in section 3 of the Stage 2 options consultation paper (tilted postage stamp (TPS), augmented nodal pricing (ANP), and load flow-based (LFB) approaches);
- (b) The detailed options designed to develop and enhance the status quo and explored in section 4 of the Stage 2 options consultation paper (options to provide incentives for participants to take

actions to defer or avoid reliability investments, and options for the treatment of HVDC costs); and

- (c) The options that arise from considering the further issues explored in section 5 of the Stage 2 options consultation paper (options for connection charging and static reactive power compensation).

4.2.3 The TPAG terms of reference also highlight that:

Any TPM options recommended by the TPAG must be consistent with the Act and therefore the Authority's statutory objective, and have regard to any Government Policy Statement (GPS) or Statement of Government Expectations in force at the time. The options must also be consistent with subpart 4 of Part 12 of the Code. Section 32(1) of the Act requires that Code amendment proposals must also be necessary or desirable to promote any or all of the following:

- a) competition in the electricity industry;*
- b) the reliable supply of electricity to consumers;*
- c) the efficient operation of the electricity industry;*
- d) the performance by the Authority of its functions;*
- e) any other matter specifically referred to in the Act as a matter for inclusion in the Code.*

In making recommendations to the Board, the TPAG must explain how the recommendations promote the Authority's statutory objective, are consistent with subpart 4 of Part 12 of the Code, and how the TPAG has applied the Authority's Code amendment principles (as published in Part 1 of the Authority's consultation charter) to arrive at its recommendations.

4.3 Analysis Framework

4.3.1 The TPAG terms of reference make it clear that the development of a preferred option and Guidelines for the TPM must be supported by an explanation of how the preferred option:

- (a) Promotes the Authority's Statutory Objective¹⁰ – this requires analysis of the degree to which the preferred option promotes competition, reliable supply, and efficient operation (as outlined in section 4.4);
- (b) Is consistent with subpart 4 of Part 12 of the Code – this requires in particular that the preferred option must be consistent with the pricing principles set out in clause 12.79 of the Code.¹¹

4.3.2 The Code Amendment Principles (CAPs) are also relevant as they are in essence an articulation of principles that will assist in meeting the Authority's Statutory Objective. It is therefore appropriate that the Guidelines and the preferred option are developed in a manner consistent with the CAPs. Although the guidelines are not part of the Code, the determination of the TPM is, and the Guidelines will direct Transpower in its development of the TPM. Any inconsistencies between the Guidelines and

¹⁰ The Authority has recently published its interpretation of its statutory objective, it is available at [http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/<http://www.ea.govt.nz/document/11845/download/our-work/consultations/corporate/statutory-objective/>](http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/http://www.ea.govt.nz/document/11845/download/our-work/consultations/corporate/statutory-objective/)

¹¹ The Authority is has published a Code amendment proposal on the regulatory framework for transmission pricing (specifically the pricing principles). It is available at: <http://www.ea.govt.nz/document/12863/download/our-work/consultations/priority-projects/regulatory-framework-tpm/>

the CAPs could lead to inconsistencies between the CAPs and the TPM. The CAPs are therefore an important part of developing the analysis framework for the Guidelines.

4.3.3 In combination these requirements provide a starting point for an analysis framework. It is noted that the requirement for consistency with the pricing principles (clause 12.79 of the Code) is currently subject to a Code amendment proposal. This complicates the process slightly because the pricing principles will be reviewed in parallel with the TPAG analysis of the preferred TPM and the development of proposed Guidelines.

4.3.4 The Statutory Objective, the CAPs, and the transmission pricing principles are considered further in the following sections.

4.4 Electricity Authority Statutory Objective

4.4.1 Section 15 of the Electricity Industry Act 2010 (Act) provides the Authority with a single statutory objective:

“To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.”

4.4.2 The Authority has finalised its interpretation of this objective and interprets its statutory objective as requiring it to exercise its functions in section 16 of the Act in ways that, *for the long-term benefit of electricity consumers:*

- *facilitate or encourage increased competition in the markets for electricity and electricity-related services, taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in those markets;*
- *encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst being robust to adverse events; and*
- *increase the efficiency of the electricity industry, taking into account the transaction costs of market arrangements and the administration and compliance costs of regulation, and taking into account Commerce Act implications for the non-competitive parts of the electricity industry, particularly in regard to preserving efficient incentives for investment and innovation.*

4.4.3 This interpretation suggests that the overall efficiency of the electricity industry is the primary objective of the Authority. Although it is useful to consider competition issues and reliability issues, these are essentially different aspects of efficiency: competitive pressures are seen as one means of achieving efficient outcomes, and standards of reliability should desirably achieve an efficient trade-off between the costs of unreliability and the costs of reliability.

4.4.4 The Authority’s interpretation of its statutory objective supports the view that the framework for decision-making about options for TPM should focus primarily on overall efficiency of the electricity sector, while recognising that competition is one of the key means applied to the electricity sector to encourage efficient outcomes. Measures that impact on reliability outcomes should encourage efficient trade-offs between the costs and benefits of reliability.

4.4.5 When considering efficiency, the key dimensions of efficiency are usefully broken down into, and assessed in terms of, productive, allocative and dynamic efficiency. Table 7 illustrates how the limbs of the statutory objective might usefully be considered within the key dimensions of efficiency.

Table 7 Efficiency considerations for the statutory objective

Statutory Objective	Competition Limb	Reliability Limb	Efficiency Limb
Productive Efficiency	Impact on competitive pressures resulting in changes to short-term costs	Impact on reliability of supply resulting in changes to short-term costs	Impact on overall short-run costs (industry and consumers) including transition costs and transactions costs associated with the different TPM options
Allocative Efficiency	Impact on competitive pressures causing changes to electricity prices that might impact on how electricity is used within the economy	Impact on reliability outcomes and flow-on impacts on how electricity is used within the economy	Impact on electricity prices and possible allocative inefficiencies
Dynamic Efficiency	Impact on competitive pressures resulting in changes to generation, consumer and transmission investments	Impact on reliability of supply resulting in changes to transmission, generation and consumer investments	Impact on overall investment efficiency (industry and consumers)

4.5 Transmission Pricing Principles [tobe updated/completed following decision on Code amendment]

4.5.1 The development of a preferred option for TPM must be supported by an explanation of how the preferred option is consistent with subpart 4 of Part 12 of the Code – this requires in particular that the preferred option must be consistent with the pricing principles set out in clause 12.79 of the Code as follows.

4.5.2 The pricing principles are currently as follows:

- a) the costs of connection and use of system should as far as possible be allocated on a user pays basis:*
- b) the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options:*
- c) pricing for new generation and load should provide clear locational signals:*
- d) sunk costs should be allocated in a way that minimises distortions to production, consumption and investment decisions by grid users:*
- e) the overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints:*
- f) transmission pricing for investment in the grid should recognise the linkages with other elements of market pricing (including the design of the financial transmission rights regime under subpart 5, and any revenues from financial transmission rights).*

4.5.3 The Authority is currently considering a Code amendment which could result in the removal of the pricing principles in their entirety; the inclusion of revised pricing principles; or the retention of the status quo.

4.5.4 Analysis by the Authority suggests that the transmission pricing principles should be removed from the Code and that TPM guidelines would be better assessed against the Statutory Objective. Alternatively, the existing transmission pricing principles could be replaced by a revised set of principles reflecting the Statutory Objective. The revised (draft) pricing principles are as follows:

- a) *Ensure full recovery of Transpower’s economic costs in providing transmission services*
- b) *Promote competition by allocating cost of transmission services in a way that increases competitive pressures in the markets for electricity and electricity-related services without compromising long-term opportunities and incentives for efficient entry, exit, investment and innovation in those markets*
- c) *Promote reliability by allocating costs of transmission services in a way that encourages market participants to develop and operate the electricity system to manage security and reliability in ways that minimise total cost whilst being robust to adverse events*
- d) *Promote efficient operation which includes:*

Where practicable charging the costs of connection to the connecting party (connection charges); and

Where practicable providing locational signalling of long run transmission costs, to the extent that these are not already signalled by nodal prices, the regulatory investment test and connection charges; or

Where such locational signals are inefficient or only partially recover the balance of Transpower’s economic costs not recovered by connection charges, these residual costs should be recovered in the least distortionary manner.
- e) *Be transparent and enduring in a way that is broadly acceptable to stakeholders*

4.6 The Code Amendment Principles

4.6.1 When considering amendments to the Code, the Authority and its advisory groups are required to have regard to the CAPs to the extent that they are considered to be applicable. The CAPs are an articulation of the Statutory Objective. Although the guidelines are not part of the Code, the determination of the TPM is, and the Guidelines will direct Transpower in its development of the TPM. The CAPs are therefore not directly applicable to the development of Guidelines. However, as both the Guidelines and the CAPs are relevant to the development and determination of a revised TPM, to ensure consistency from the earliest stages, the CAPs will be a useful consideration in the development of the Guidelines.

4.6.2 The following tables summarise the CAPs and provide some commentary on how they have been considered in the context of the guidelines for TPM and criteria to be applied in evaluating TPM options.

Table 8 The Code amendment principles 1 to 3 and their application to the TPM Guidelines

Principle		Key Points from Code Amendment Principles (CAP)	Applicability to TPM Guidelines
1.	Lawfulness	<ul style="list-style-type: none"> • Must be consistent with Statutory Objective 	<ul style="list-style-type: none"> • To be consistent with the Statutory Objective the guidelines for TPM must promote efficiency, competition and reliability.

Principle		Key Points from Code Amendment Principles (CAP)	Applicability to TPM Guidelines
2.	Clearly Identified Efficiency Gain	<ul style="list-style-type: none"> • Must be able to demonstrate an efficiency gain or a market failure or problem with Code • To be used as a form of screening test 	<ul style="list-style-type: none"> • Only TPM options that promise clear improvements to market efficiency, or correction of an identified market failure, should be considered • The criteria for evaluating options should focus on efficiency gains (dynamic, productive, and allocative efficiency) • This principle could be usefully applied to screening high level options in particular
3.	Quantitative Assessment	<ul style="list-style-type: none"> • Quantitative CBA to assess long-term benefits • Competition and reliability effects are to be assessed within CBA framework • Dynamic efficiency is particularly important • Sensitivity analysis is required 	<ul style="list-style-type: none"> • Quantitative CBA should be applied to assess long-term benefits associated with each of the detailed options • Competition and reliability effects should be assessed within the CBA framework • Analysis of dynamic efficiency effects should be given emphasis within the CBA framework • The CBA should include sensitivity analysis

4.6.3 Principles 1-3 are the primary principles to be applied to the development of TPM Guidelines. In the event that the application of these primary principles is inconclusive about which is the best option a number of “tie-breaker” principles would be applied as follows.

Table 9 Code amendment principles 4 to 9 and their possible application to the TPM Guidelines

Tie Breaker Principle		Key Points from Code Amendment Principles (CAP)	Applicability to TPM Guidelines
1.	Preference for Small-Scale Options	<ul style="list-style-type: none"> • Favour small-scale trials 	<ul style="list-style-type: none"> • To the extent that it can be implemented incrementally from the status quo
2.	Preference for Competition	<ul style="list-style-type: none"> • Prefer options that focus on competition to achieve efficiency gains 	<ul style="list-style-type: none"> • If CBA is inconclusive then place a preference on options that increase competition
3.	Preference for Market solutions	<ul style="list-style-type: none"> • Prefer options that focus on efficient market-based structures 	<ul style="list-style-type: none"> • If CBA is inconclusive then place a preference on options that focus on market-based arrangements • Could have particular application where TPM addresses transmission alternatives

Tie Breaker Principle		Key Points from Code Amendment Principles (CAP)	Applicability to TPM Guidelines
4.	Preference for Opt-Out Features	<ul style="list-style-type: none"> Prefer options that give participants opt-out options However, non-rivalry and non-excludability conditions will favour “one size fits all” approach 	<ul style="list-style-type: none"> TPM is a case where non-rivalry and non-excludability conditions generally favour “one size fits all” approach Careful use of opt-out features could be considered in particular circumstances
5.	Preference for Non-Prescriptive Options	<ul style="list-style-type: none"> Focus on options that specify outputs rather than inputs 	<ul style="list-style-type: none"> Not applicable as the Code requires a TPM
6.	Risk reporting	<ul style="list-style-type: none"> Final tie-breaker if CBA is inconclusive and principles 5-8 do not discriminate Report required to assess risks of proceeding or not proceeding with option 	<ul style="list-style-type: none"> A report assessing the risk of proceeding with the preferred option or retaining the status quo should be included

4.7 Criteria for Evaluation

4.7.1 The decision framework applied by TPAG is based on the statutory objective as expanded on in the first three CAPs interpreted as follows:

- (a) Consistent with the Statutory Objective – TPM must promote efficiency, competition and reliability;
- (b) Clearly identified efficiency gain – any change to the TPM must demonstrate a clear efficiency gain or resolve a market failure;
- (c) Quantitative assessment – CBA must be applied to assess the relative efficiency benefits of the TPM options with a particular focus on dynamic efficiency, and including sensitivity analysis.

4.7.2 The experience of decision-making on regulatory issues in the electricity sector suggests that, while a focus on efficiency outcomes taking into account specific outcomes for competition and reliability is a sensible approach, the resulting (CBA) is often insufficient on its own to inform correct decisions. This is because sensitivity analysis will often create overlapping ranges of CBA values and many benefits and costs are difficult to quantify. A range of other factors are therefore useful in informing a final decision between particular options as they highlight some particular aspects of efficiency which may tend to be overlooked in quantitative assessments of efficiency gains. It is useful to consider them in parallel with the more quantifiable components of efficiency.

4.7.3 A proposal cannot be “efficient” if it cannot be implemented, or sustained, and proposals that are unnecessarily complex or controversial imply ongoing “transaction costs” which, in aggregate across the industry, can be quite substantial. Also, since this is only a partial analysis, in the sense that it only focuses on one of many parallel changes now in train, it should be recognised that substantial inefficiencies could arise if an option was chosen that did not fit well with those other developments.

4.7.4 The following table summarises the recommended set of criteria to be applied in evaluating TPM options.

Table 10 Evaluation criteria

Category	Criterion	Measure
Dynamic efficiency	For any proposal we need to understand any potential impacts on dynamic efficiency, in terms of investment incentives for transmission, generation, load, DSM etc with particular emphasis on competition and reliability	Quantitative / Qualitative
Productive efficiency	For any proposal we need to understand any potential impacts on productive efficiency with particular emphasis on increasing competitive pressures, minimising administrative and operating costs and promoting reliability	Quantitative / Qualitative
Allocative efficiency	For any proposal we need to understand any potential impacts on allocative efficiency with particular emphasis on the alignment of price signals with marginal costs on an operational time scale	Quantitative / Qualitative
Fit	Any proposal needs to be logical and workable, while applying a philosophy consistent with other parts of the market design and how that is expected to evolve	Qualitative
Durability	It is important that any proposal can generate a reasonable degree of support from sector stakeholders, both now and in any likely future circumstance.	Yes/No/maybe? Qualitative
Implementation risk	Any proposal must be readily implemented within a reasonable timeframe, taking into account disruption costs and transactions costs	Quantitative / Qualitative
Flexibility and robustness	Any proposal needs to provide the ability to adapt to a reasonable variety of possible future scenarios, while continuing to deliver appropriate outcomes	Qualitative

4.7.5 These criteria are consistent with the Statutory Objective, the CAPs, [and the draft revised transmission pricing principles]. However, they also provide some expansion of the efficiency criteria that will usefully inform the transmission pricing evaluation.

4.8 Cost Benefit Analysis - Counterfactual

4.8.1 The CAPs make it clear that a key element of any evaluation of TPM will be a cost-benefit analysis (CBA). The CBA will need to explore all the credible options and justify the preferred option relative to some form of status quo counterfactual (or counterfactuals?).

4.8.2 An important issue to consider in the context of the CBA, particularly with the analysis of the preferred option, is the definition of a counterfactual against which to measure the option. The counterfactual should include:

- (a) The status quo TPM;
- (b) Possible future electricity sector development as defined by the range of futures outlined in the latest SOO (varied appropriately where there may be material differences in the results);
- (c) Scarcity Pricing introduced such that an administered price floor would prevail at all South Island nodes (or all North Island nodes), if the System Operator has instructed load shedding during a Grid Emergency throughout the South Island (or throughout the North Island), and a different

administered price floor would prevail at all South Island nodes (or all North Island nodes) where the System Operator has instructed participants to implement rolling outages throughout the South Island (or throughout the North Island);

- (d) Some form of financial transmission right (FTR) between designated North and South island nodes, made available to participants via an auction process, with the holder of any FTR receiving the market surplus rentals between the island hubs¹². The proceeds from the auction will be distributed in the same manner as existing market surpluses – i.e. to those participants paying the charges associated with the assets between the North and South Island nodes.
- (e) Other options for both scarcity pricing and locational hedging should also be considered in the counterfactuals, where these are possible outcomes for these projects.
- (f) A transmission alternatives regime, overseen by the Commerce Commission, that encourages Transpower to consider alternatives to transmission investment, and is essentially similar to the existing regime.

4.9 Impact of Regulatory Change on Work Undertaken to Date

4.9.1 TPAG has noted that the Transmission Pricing Review was commenced by the Electricity Commission within the framework of the Electricity Act 1992 and the Electricity Governance Rules 2003 and is now being advanced by the Electricity Authority within the framework of the Electricity Act 2010 and the Electricity Industry Participation Code.

4.9.2 The change in statutory framework has resulted in the Authority being guided by a different set of statutory objectives from those that guided the Commission. TPAG has therefore been concerned to ensure that work undertaken and the TPM options developed by the Commission, remained consistent with the statutory objectives of the Authority.

4.9.3 Appendix [X] outlines the TPAG consideration of the impact of the change in statutory objective on the work undertaken to date by the Commission. The conclusions are as follows:

- The Commission’s principal objective and specific outcomes covered a broad range of issues, but in particular, the Commission was required to consider the impact of its proposals on efficiency, fairness, reliability and environmental sustainability.
- In contrast, the Authority has a narrower statutory objective with a focus on competition, reliability and efficiency, without any specific references to fairness or environmental sustainability.
- The Authority interprets its objective to centre on efficiency considerations, given the overall requirement to act in a way that is “*for the long-term benefit of consumers*”. The Commission also treated efficiency as its guiding principle and this can be confirmed through a review of decision documents published by the Commission covering a range of issues.
- Changes to the statutory framework are sufficiently significant that regardless of the current Review, the validity of the current TPM under the new framework would need to be considered at some point.

¹² Or possibly between designated nodes.

- Stages 1 and 2 of the Review (conducted by the Commission) were primarily focussed on efficiency considerations, with an evaluation of the wider regulatory framework to be addressed in stage 3:
 - the options developed in Stage 1 were focussed on the efficiency benefits of location-based transmission prices;
 - the analysis of options that could provide incentives to avoid/defer reliability investments developed in Stage 2 were focussed on the efficiency benefits of transmission price signals;
 - the analysis of options for allocating HVDC costs were focussed on efficiency outcomes in the generation market; and
 - the analysis of options for pricing Static Reactive Compensation were focussed on incentives to minimise costs.
- The development of these TPM options was not influenced by fairness or environmental sustainability considerations.
- The changes to the statutory framework during the course of the transmission pricing review project do not require the Commission's analysis and development of alternative TPM to be reworked, and the options developed through Stages 1 and 2 of the Review were developed in a manner consistent with the Authority's statutory objective.

5 Approach to Assessment

As noted at the start of section 4, sections 4 and 5 need to be tightened (possibly amalgamated) and more closely tied back to the statutory objective.

5.1 Introduction

5.1.1 It is important to consider the role of the Transmission Pricing Methodology (TPM) in the context of the existing regulatory and market environment as summarised in the table below.

Table 11 The Transmission Pricing Methodology in context

Consideration	Description
Transmission is a regulated monopoly	<ul style="list-style-type: none"> • Central planned and separate Commerce Commission regulation of new investment in transmission. <ul style="list-style-type: none"> ○ Grid users can commercially negotiate for extra services and assets and these are not regulated, but incentives to do this may be undermined by backstop of central planning • Commerce Commission determines the revenue requirement and approves investment in transmission (and alternatives) on the basis of a Grid Investment Test (GIT). • The TPM sets out how revenue is to be allocated between and recovered from Transpower’s customers.
Electricity generation market is commercial and competitive	<ul style="list-style-type: none"> • Commercial, market based new investment in generation • Commercially determined generation offers and central market clearing. • Full nodal spot pricing • Full open access to grid at marginal cost <ul style="list-style-type: none"> ○ No physical “dispatch” rights on the grid, but full signalling of congestion and losses. • Scarcity pricing by Island (not node) is proposed. • Inter Island hedging rights to be auctioned is proposed.

5.1.2 The following Table 12 summarises the range of important efficiency considerations involved in Transmission pricing. These efficiency considerations can be broken down into productive, allocative and dynamic efficiency aspects. Competition is an important tool to promote efficiency, and there should be an efficient trade off between the cost and value of reliability. It should also be recognised that these efficiency considerations apply in the electricity market as well as in the centrally planned transmission investment and regulatory processes. The latter are often difficult to quantify as they relate to incentives arising from the nature of the investment and regulatory processes but can be very significant.

Table 12 Efficiency considerations

Consideration	Implication
Location price signalling	Provide additional location price signals if these promote more efficient: <ul style="list-style-type: none"> - coordination of investment and use of transmission, generation, and DSM; or - trade-offs between the costs and benefits of reliability.
Economic distortions	Minimise economic distortions arising from the TPM. Provide a level playing field for long term competition in generation and retail.
Beneficiary pays	Apply a beneficiary pays approach: <ul style="list-style-type: none"> - to incentivise participants to provide quality information to the planning and investment process, and promote commercially-driven investment. - where beneficiaries can be clearly identified, and benefits outweigh costs.
Good regulatory process	Adopt a consistent, robust and durable TPM (over full investment cycle) to minimise incentives for rent seeking and promote dynamic efficiency. Avoid changes unless justified by efficiency. Provide for transition if necessary.
Simplicity & workability	Keep transaction and regulatory costs to an efficient level.

5.1.3 The implications of these efficiency considerations are discussed below.

5.2 Locational Price Signalling

5.2.1 The objective of locational price signalling is to achieve an efficient co-ordination of generation, demand-side and transmission investment, and efficient dispatch of generation and operation of demand management.

5.2.2 As a general rule the nodal spot market provides good signals for dispatch and use of the transmission grid. However it only provides reasonable, but not perfect, signals for location of new generation for reasons relating to economies of scale, lumpiness, lack of scarcity pricing at a nodal level and the process of centrally planned and regulated transmission investment¹³. The TPM may be used to augment locational price signals from the nodal spot market in these situations.

5.2.3 The regional structuring of Regional Coincident Demand Peak (RCDP) interconnection charges is an attempt to provide additional price peak demand management signals in regions with growing net demand¹⁴ requiring transmission “reliability” investments.

5.3 Economic distortions - Allocating fixed and sunk costs in the least distortionary manner

5.3.1 A key function of the TPM is to provide a mechanism for Transpower to recovery its fixed and sunk costs (i.e. allowed revenues) from customers. Any practical form of sunk cost recovery will involve

¹³ Regulated transmission investment based on the grid investment test and meeting grid reliability standards can lead to prudent, early and lumpy transmission investments which can lead to inadequate locational signals for generation and load management.

¹⁴ The RCDP charge is allocated on the basis of the average of the highest 12 (rather than 100) trading period demands in the upper south and upper north islands where demand growth is leading to increasing investments in the grid for reliability reasons. This is an attempt to “correct” nodal prices for a lack of scarcity pricing

some unintended price signal and hence distortion. As a general rule the TPM aims is to minimise these economic distortions by allocating costs to those whose behaviour is unlikely to be influenced by the unintended signals. The only exception to this is where the price signals provided by the TPM are specifically designed to correct for inadequate locational price signals in the nodal spot market (as discussed above).

- 5.3.2 This consideration typically requires spreading the cost as much as possible as this tends to make cost recovery signals weaker and harder to avoid. It also often implies that fixed costs should be recovered from customers rather than generators as generation dispatch and location decisions are often more responsive to price signals than demand.
- 5.3.3 The current RCDP interconnection charges are spread over all customers in an attempt to minimise distortions¹⁵.
- 5.3.4 This consideration also implies that the TPM should pay attention to boundary issues (e.g. categorisation of different users or deep and shallow assets) as this may provide unintended incentives and result in lobbying and distortions.

5.4 Beneficiary pays - Role of beneficiary pays in achieving efficient outcomes

- 5.4.1 Even though most transmission investments are centrally planned and approved subject to an investment test, there is potential economic benefit in a beneficiary pays approach to transmission pricing.
- 5.4.2 Parties that pay have an incentive to participate in decision-making and to provide more accurate information to Transpower and the Commerce Commission, while testing the options and costs proposed by Transpower. A beneficiary pays approach also provides improved incentives for parties to negotiate separate commercial agreements for some “economic” investments in the grid which may not need to be centrally planned and regulated.
- 5.4.3 This approach is particularly useful where individual beneficiaries can be clearly and robustly identified and where allocation of costs to beneficiaries does not distort new generation or demand investments. However there are limits to the application of this approach in a centrally planned and regulated investment environment. A beneficiary pays approach may not be justified in a situation where identification of beneficiaries is costly, ad-hoc or subjective (as this provides an incentive for lobbying rather than good information) or where the allocation of costs between large groups of assessed beneficiaries results in significant distortions of dispatch or investment in generation or load management.
- 5.4.4 Note that even under postage stamp transmission pricing, users have a general incentive to participate and provide accurate information. This incentive is not altered very much if there is a very broad beneficiary pays allocation of costs; however it may be significantly improved if a very specific beneficiary (or beneficiary group) can be clearly identified.
- 5.4.5 Where a beneficiary pays approach is used the greatest value can be obtained by having it linked to investment decision making. Ideally the beneficiary assessment should reflect the value parties would have been prepared to pay prior to committing to lumpy “sunk” investments (i.e. ex-ante). The allocation of costs to beneficiaries should then be “fixed” at the time of each significant grid

¹⁵ Note that although the RCDP charges are uniform they are structured to provide a stronger additional peak demand management signal in particular regions where there are, arguably, inadequate nodal price signals.

investment (i.e. not changed arbitrarily ex-post). Ideally the cost allocation to beneficiaries should be structured so as to minimise any distortion in use of the new investment¹⁶.

5.4.6 The current TPM very successfully applies a beneficiary pays approach to connection assets.

5.5 Good regulatory practice

5.5.1 Poor regulatory practice in itself can lead to significant inefficiencies if it creates regulatory uncertainty or incentives for wasteful lobbying.

5.5.2 Ideally regulation should follow a principled consistent approach across the across the different grid assets and over time. This enables market participants to more easily predict future regulatory behaviour, and it also minimises the incentives for lobbying.

5.5.3 Ideally the approach should be applicable in a situation where significant new investments are being considered and where these investments have been just committed.

5.5.4 To the extent possible, pricing methodologies should be transparent, easily understood, justified and defensible. Excessively arbitrary, subjective or ad-hoc methodologies should be avoided. Pricing outcomes should be broadly acceptable to grid users and other stakeholders to ensure that the methodology is sustainability and does not trigger political interventions.

5.5.5 Dynamic efficiency is enhanced if the approach to the TPM is kept reasonably constant. Circumstances will change over time and this may require modifications to the TPM, but changes that result in wealth transfers should be justified by efficiency improvements. Where change is justified then it should be well signalled in advance and a transition should be provided so that participants can have time to adjust.

5.6 Simplicity and workability

5.6.1 Simplicity and workability should take into account implementation and transaction costs for industry participants, Transpower and the Electricity Authority.

5.7 Developing a path through the options

5.7.1 All of these different aspects of efficiency need to be addressed when considering the options. While it is possible to approximately quantify economic distortions associated with TPM options, it is recognised that the benefits of beneficiary pays and good regulatory practice are more difficult to assess but can be significant.

5.7.2 The potential benefits of stage I high level options to provide additional locational signalling to better coordinate generation and transmission investments is reviewed in section 7. This confirms the stage 2 conclusion that the benefits of these options are unlikely to outweigh the costs.

5.7.3 The key focus is on the range of HVDC options which could be implemented within the allowed timeframe. Section 8 attempts to quantify the economic distortions arising from the current methodology and considers options to reduce or remove these distortions while also recognising the potential efficiency gains from following good regulatory practice and a consistent approach to

¹⁶ The theoretical ideal would be for beneficiaries to be charged a lump sum (or fixed annuity) for lumpy new investments. In practice this is seldom achievable because "fairness" considerations and difficulties involved in determining individual beneficiary shares through a regulated central planning process rather than through commercial negotiation. Often relatively arbitrary usage based allocation methods are the only practical option. These options are most prone to creating economic distortions.

beneficiary pays. The potential costs and benefits of applying a capacity rights approach are also considered.

- 5.7.4 [Section 9 considers options (such as specific and general Bespoke, flow trace and “but for” options) to provide additional signals to defer transmission “reliability” investments. This recognises that the current TPM already provides additional price signals through the structure of the RCDP interconnection charges which provide a stronger signal for peak demand management in regions with growing net demand. Section 9 also recognises that the Commerce Commission regulated “Transmission Alternatives” process enables generation or demand side options to be commercially contracted for by Transpower where these are efficient. The tentative conclusion is that the options set out in section 9 are relatively complex pricing methodologies and may not provide sufficient additional benefit to offset their implementation and operation costs. They may also create conflicts with Transmission Alternatives regime. However there may be benefit in refining the existing RCDP charging mechanism and/or the regulated Transmission Alternatives process.]
- 5.7.5 [Section 10 considers the other options relating to deep and shallow connection and static reactive compensation pricing.]

6 Overview of the options

[Note: this section is yet to be reviewed for consistency with subsequent sections which draw on it]

6.1.1 This section provides a high-level overview of the transmission pricing options considered in the Stage 1 and 2 consultation papers, and options suggested by submitters. The options are organised in four sections:

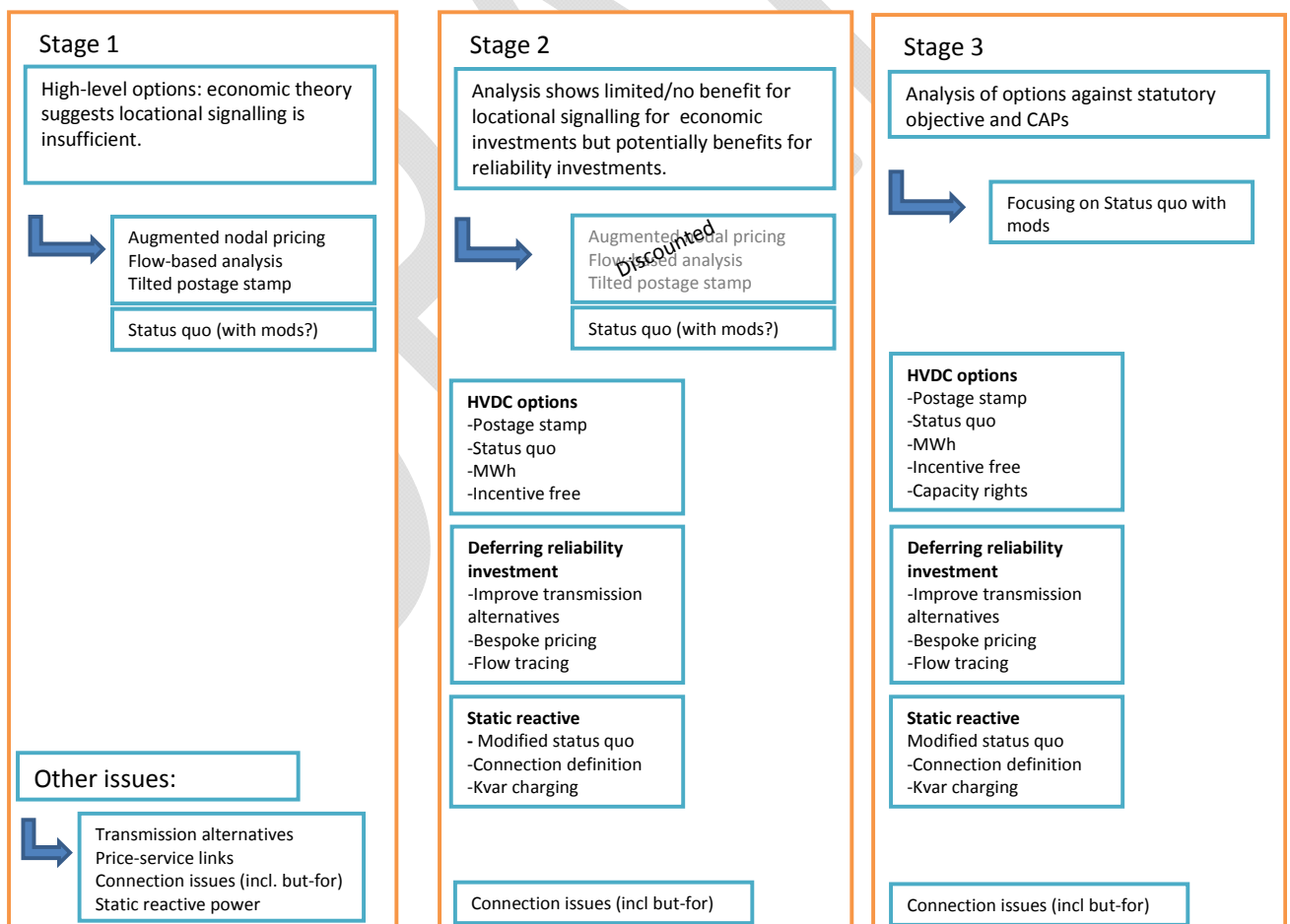
- (a) The stage I high-level options
- (b) HVDC options
- (c) Options for deferring reliability investment
- (d) Other options

6.1.2 **Error! Reference source not found.** below illustrates this grouping of the options, mapped onto the three stages of the Review depicted in

6.1.3 Figure 2 above and described in Section 3.

6.1.4 The TPAG's assessment and recommendations set out in this Discussion Paper are based on its application of the analysis framework (refer Section 4) to the options described here.

Figure 3: Overview of the options through the Review process



6.2 Stage I high-level options

Background to the stage I high-level options

- 6.2.1 Stage 1 considered issues with the current transmission pricing, economic theory and international experience. In order to distinguish high-level option issues from more detailed considerations, the focus of stage 1 was economic theory considerations in particular whether there was sufficient justification to consider enhanced locational signalling in addition to that provided by nodal pricing, deep connection and the grid investment test.
- 6.2.2 Nodal pricing, the connection charging regime and the grid investment process already provide some locational signalling, but the economic theory investigated in stage 1 suggested that this was likely to be insufficient (in a true economic sense) due a trio of factors: the use of deterministic reliability criteria in transmission investment approvals, economies of scale and timing considerations in transmission investment, and the inaccurate pricing of supply security (i.e. the absence of nodal scarcity pricing).
- 6.2.3 Stage 1 identified three alternatives to the status quo transmission arrangements that might provide enhanced locational signalling. These three were considered alongside the status quo. These are described below.
- 6.2.4 Stage 1 also considered four issues that had been raised with the current regime: the lack of a link between price and service, issues with connection arrangements, transmission alternative arrangements and static reactive compensation. These issues are not considered here as they did not contribute to the development of the initial high-level options. Their consideration contributed to the development of some of the options described in section 4 and 5.

Status quo arrangements

- 6.2.5 The current transmission pricing methodology (TPM) comprises:
- A connection charge that recovers the costs of dedicated and spur-line assets connecting participants to the interconnected grid.
 - An interconnection charge imposed on load that is the function of both a postage-stamped interconnection rate and the customer's contribution to the regional coincident peak demand (RCPD).
 - A postage stamp charge on South Island generators charged on historical peaks to recover the costs of the existing HVDC link and any augmentations to it.
- 6.2.6 The Stage I consultation paper asked submitters whether their might be relatively minor modifications that could be made to the existing TPM to enable it to provide appropriate locational signals.

Tilted postage stamp approaches

- 6.2.7 Under this approach, charges are postage stamped, but are higher for loads in predominantly importing regions and lower for loads in predominantly exporting regions. If future load growth in New Zealand follows historical trends, this should lead to higher charges for loads in the North Island than loads in the South Island. If this charging method were to be applied to generators, it would apply in an inverse manner; generators in the South would face higher charges than those in the North. A number of methods of applying a tilted postage stamp approach have been suggested from charging

based on latitude, or based on the grouping of participants' grid exit points within geographic zones. This approach was considered by NERA in its work for the CEOs' Forum¹⁷. NERA considered that tilted postage stamp approaches could involve a few zones or possibly a more granulated approach.

Augmented nodal pricing

- 6.2.8 This approach seeks to directly address the deficiencies in nodal energy pricing. It is based on an assumption that the current regime results in excessive or premature network investment, and that it is possible to identify those generators and loads that benefit most from this investment. Under this approach, transmission charges would be highest for those that benefit most from this investment, and lowest or even negative for those that are made worse off as measured by market prices. The application of this approach depends on being able to identify transmission investment that is in excess of purely economic investment, and also further identifying which parties benefit and which parties lose out as a result of any excessive investment.

Load flow-based approaches

- 6.2.9 Load-flow based transmission pricing options involve a process of network analysis to attribute costs to participants based on identifying the network assets they use. These approaches can be based on flows on the existing network as in Australia where a method called Cost Reflective Network Pricing is used. They can also use forward-looking network analysis and costs as in the UK where 'Investment Cost Related Pricing' is used. A load-flow-based approach has previously been used in New Zealand but was replaced owing to concerns over complexity and excessive variability of transmission prices.

The Commission analysis on the stage I high-level options

- 6.2.10 The purpose of stage II was to support the Commission's decision-making as it narrowed down the possible options for a transmission pricing methodology. Following stage I and considering the views of submitters, the Commission concluded in stage II that given the factors mentioned earlier in paragraph 2.3.1, it is unlikely that - theoretically - nodal pricing will always provide adequate signals for efficient generation and load investment. Stage II analysis then considered whether there would be benefits in practice in implementing a new TPM with enhanced locational signalling.
- 6.2.11 The Commission undertook substantial analysis to estimate the potential upper bound of economic benefits from providing further locational signals through the TPM. This was done by modelling 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 ie 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).
- 6.2.12 The Commission's used the Generation Expansion Model (GEM) to derive an estimate of overall system costs for the different scenarios¹⁸. The Commission's analysis suggests that the upper bound of benefits of implementing locational signals through the TPM to signal to generation the cost of

¹⁷ Available at <http://www.ea.govt.nz/document/6616/download/our-work/programmes/priority-projects/transmission-pricing-review/>

¹⁸ An appendix to the stage II consultation paper describes the analysis: <http://www.ea.govt.nz/document/9995/download/our-work/consultations/transmission/tpr-stage2options/>

economic transmission investment¹⁹ appears to be immaterial. Further, it is possible that a transmission pricing regime, if not precise enough, could lead to unintended inefficiencies by over-signalling locational costs and induce poor investment decisions around the type, timing and location of generation.

- 6.2.13 The Commission's position set out in the stage II consultation paper was that there was no justification to progress further work in developing augmented nodal pricing, load flow-based approaches or tilted postage stamp as the basis for any future TPM to avoid economic transmission investments. This position was based on the lack of material benefits from locational signalling for economic transmission investments, and the likely complexity associated with each of the high-level options intended to enhance locational signalling.
- 6.2.14 The Commission's preference, expressed in the stage II consultation paper, was for a TPM based on the status quo. It suggested some modifications to the status quo where benefits could be demonstrated including:
- (a) Options for the HVDC charging regime
 - (b) Options for deferring reliability transmission investments
 - (c) Other modifications such as changes to the static reactive compensation arrangements and connection arrangements
- 6.2.15 Although the focus of the TPAG analysis and assessment of options should be on the modifications to the status quo, it is necessary to meet the TPAG terms of reference by undertaking and summarising an assessment of the high level options outlined in the stage 1 options paper. This could be undertaken through a combination of qualitative and quantitative assessments based on existing work.
- 6.2.16 The objective is to solidify the understanding of the GEM "co-optimisation" analysis in particular (because it is a significant factor in eliminating some of the high level options) and to ensure that there is general support for eliminating the TPS, ANP and LFB based approaches to recover all transmission costs from load and generation.

6.3 Options for the HVDC charging regime

Background to the HVDC options

- 6.3.1 The Commission's stage II analysis on the benefits of locational signalling concluded that there was no material value in providing for an enhanced locational signal to generators through the interconnection charge. There is currently no locational transmission pricing signal for AC interconnection assets for generators. The situation is different for HVDC assets.
- 6.3.2 The current HVDC charge is levied on all South Island generators that inject into the Grid (including new generators). As such, it provides a locational signal to invest in generation in the North Island in preference to the South Island.
- 6.3.3 The stage 2 consultation paper presented an analysis showing the costs and benefits of the current design of the HVDC charge (relative to a regime with no charges on SI generators and no incentive effects). This analysis suggested that there may be material benefits in alternative HVDC charging

¹⁹ Economic transmission investments are those investments that reduce system costs as opposed to reliability transmission investments that are required to meet demand.

regimes. The stage II paper suggested three options alongside the status quo, and also considered market-based alternatives suggested by NZIER. These options are described below:

The status quo

- 6.3.4 Under the current transmission pricing arrangements the HVDC costs are met through a charge on South Island generation plan with charges based on Historical Anytime Maximum Injection (HAMI) into the grid at the customer's location ie a charge on historical peak injection. Charges are not levied on generation embedded in a lines network.

MWh charge

- 6.3.5 Under this option, the HVDC charge would remain on South Island generators but would be allocated proportionately to generation in MWh. The effect of changing to a per-MWh charge would be to avoid penalising peak injections and hence avoid discouraging investment in peak generation or generators operating to their peak capacity. 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-on-year variation. Some submitters to the stage II consultation paper suggested a variant of this charging regime, with the MWh charge levied on both North and South Island generators depending on the direction of flow on the HVDC link. Other submitters suggested that the MWh charge could be levied on a mixture of load and generation, again depending on the direction of flow on the HVDC link.

Incentive-free allocation to South Island generators

- 6.3.6 Under this option, the HVDC charge would remain on South Island generation plant, but in an 'incentive-free way' that does not distort operational or investment decisions. Generation assets in existence at 'X' date would cover the costs of the HVDC charge. Both NERA and the Commission considered an incentive-free approach, but noted practical issues.

Postage stamp

- 6.3.7 Under this option HVDC costs would be spread broadly throughout New Zealand over load, in the same manner as interconnection assets are charged currently. Alternatively the charge could be shared with generation.

HVDC capacity rights

- 6.3.8 NZIER proposed alternative options for the HVDC charge, initially in response to NERA's work with the CEOs' Forum, but also as part of submissions to both the stage I and stage II consultations. NZIER suggested two market-based approaches to charging for the HVDC, one involved an arbitrageur approach and capacity rights approach. Only the capacity rights option is included here because the arbitrageur approach would be outside of the scope of the transmission pricing review and the Authority's responsibility requiring an asset sale or Transpower's involvement in the energy market.
- 6.3.9 The basic principle of the capacity rights approach is that generators would need to purchase capacity rights in order to use the HVDC link. The approach, as described at a high-level by NZIER, would involve introducing three new trading processes:
- (a) an annual allocation of capacity rights at Transpower's unit cost based on historical usage;
 - (b) a secondary trading market for capacity rights that would operate up to the start of the half-hour to which a capacity right relates; and

- (c) spot trading of capacity rights which would operate in conjunction with the offering of generation for dispatch.

6.3.10 The Commission considered that in its stage II consultation paper that the capacity rights approach should not be progressed further. This was due to the 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. Although the Authority continues to have concerns about the capacity rights approach it has further considered whether the design of a possible capacity rights option could be improved and considered alongside the other HVDC options, and proposes that it be included in the TPAG assessment.

6.4 Options to defer reliability investments

Background to the options to defer reliability investments

6.4.1 Reliability investment is primarily to support reliable supply to load. The need for such investment tends to be driven by peak demand. Avoiding or deferring the costs of reliability-driven investments typically involves investment in alternatives – namely demand-side management 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. The stage II consultation paper considered the possible benefits from providing further signalling or other mechanisms for deferring reliability investments.

6.4.2 In summary, the analysis concluded that there is predicted to be a steady growth in peak demand, with a resulting need for investment in transmission assets, or in alternatives. There could be significant efficiency gains if demand side management or peak generation is located in regions where transmission investment would otherwise be made.

6.4.3 The stage II consultation paper suggested three options for providing mechanisms to defer reliability investments:

Bespoke pricing

6.4.4 This is an 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 on-going need for reliability investments. This term was used in the NERA report as a tilted postage stamp regime customised for specific regions. Participants in other regions would continue to face the standard interconnection charge that would apply only to loads. In subsequent work for the Commission, Covec²⁰ has proposed two models of 'bespoke pricing'.

- (a) A "specific bespoke" pricing option that is in effect a form of transmission alternatives regime whereby a customised pricing signal could be triggered in a region when a reliability investment is listed in the Grid Reliability Report (GRR).
- (b) A "general bespoke" pricing option which involves dividing the grid into regions in which connected entities would receive positive or negative price signals depending on whether their supply of off-take would exacerbate or mitigate the need for reliability investment within their region.

²⁰ Bespoke Pricing Signals; report prepared for Electricity Commission, October 2010.

6.4.5 The status quo already provides some customised pricing signals for load via the differentiated RCPD regime.

Flow-tracing

6.4.6 A flow-tracing approach seeks to allocate a proportion of interconnection assets to specific connected entities based on their use of the transmission grid as determined by applying a flow-based measure of usage. This could involve either deepening the definition of connection, or allocating some portion of the currently postage stamped interconnection costs to individual loads.

6.4.7 Allocating a greater portion of interconnection costs to individual customers should provide a greater incentive 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. It should also motivate customers to scrutinise transmission investments more closely.

6.4.8 Flow tracing is a method which is able to calculate the electrical usage of assets by participants. This is achieved through the calculation of Average Participation (AP) factors, for each individual electrical asset, based on historical data. For transmission pricing, these AP factors are then used to allocate the costs of transmission assets.

6.4.9 The intention would be to allocate only a portion of the interconnection assets using flow-tracing; the assets that are used by a small number of individual customers. The costs related to the unallocated interconnection assets would be recovered via postage stamping.

Improved transmission alternatives

6.4.10 The possibility of improving the transmission alternatives regime in order to provide a more direct means of procuring generation or demand response to avoid or defer reliability (and/or economic) transmission investment was also considered as an option in stage II. However, the transmission alternatives regime is essentially part of the process that must be applied by Transpower when it is considering transmission investments and applying the Grid Investment Test (GIT). This process is now overseen and regulated by the Commerce Commission, and therefore outside the scope of this work. Nevertheless, it will be important, when developing and evaluating transmission pricing options, that their fit with the transmission alternatives regime be taken into account.

6.5 Other options

6.5.1 The options described in this section have been considered as part of the 'further issues' work which has run through the transmission pricing review to date.

But-for approach/ deeper investment cost allocation through the Grid investment process

6.5.2 This approach has been put forward in this and earlier reviews by MEUG. The so-called 'but-for' approach is used in PJM essentially as a deep connection charge to large generators and load. The new connections are charged both connection costs and any interconnection augmentations that would not have been needed but for the new connection. In PJM the new connection (generation or load) receives capacity rights in return for its charges. The Commission ruled out this approach owing to its complexity, likely subjectivity and difficulty of implementation (particularly in the NZ where the market model does not include capacity rights).

6.5.3 In its submission to the stage II consultation paper, MEUG continued to favour the but-for approach, and suggested that there may be innovative ways to apply it in NZ. In subsequent discussions with

MEUG, MEUG has suggested that its interest in but-for is primarily an interest in allocating costs of new investment to beneficiaries and that it might be feasible to achieve this as part of the Grid investment process rather than a but-for approach.

Changes to the connection regime

6.5.4 Possible changes to the connection regime have been suggested by parties. They are:

- (a) Creating a shallower or deeper definition of connection – this could be through adjusting the boundary definitions in the current TPM, or by applying a flow-tracing approach.
- (b) Creating a backstop arrangement for new connections assets where there are practical issues that may hamper mutually-negotiated shared arrangements new connections.

Static reactive options

6.5.5 The stage II consultation paper outlined three possible options for allocating static reactive power costs. These were:

- (a) **Amended status quo.** This would involve amending the current standard in the Connection Code and retaining this as a basis for determining the allocation of costs for static reactive power investments.
- (b) **Connection asset definition.** This would involve widening the definition of connection asset to include new static reactive power investments.
- (c) **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. Transpower suggested a variation of the kvar charge option in its submission to the stage II consultation paper which involves treating static reactive assets as interconnection assets and charging using reactive draw at peak demand periods.

6.5.6 There is a strong linkage between arrangements to incentivise efficient investment in static reactive compensation and options for deferring reliability investments.

7 Location-based Price Signals

7.1 Background

- 7.1.1 The focus of Stage 1 of the transmission pricing review 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. An enhanced locational signal would be in addition to the existing signals provided by nodal pricing, the application of the relevant grid investment test, the shallow and deep connection definitions and the HVDC charge. A central part of the Stage 2 analysis that followed was to build on this to assess whether there were potential benefits in introducing further locational signalling. The Generation Expansion Model (GEM) was a key tool in this analysis.
- 7.1.2 The results from the GEM analysis were surprising to the extent that people expected to see a bigger benefit from locational signalling. The results suggest there is limited benefit in providing enhanced locational signals to generators to ensure co-optimisation of economic transmission investments and generation. From this, the Commission formed a preliminary view that there may be little justification for imposing additional transaction costs on the industry in order to introduce further locational signalling through transmission pricing in respect of economic investments. The Stage 2 Consultation Paper presented (amongst other things) this preliminary view and sought industry feedback on it. Submissions received were largely supportive of this conclusion drawn from the GEM analysis.
- 7.1.3 This conclusion, and the GEM analysis that underlies it, is pivotal to the work of the TPAG and the direction of the Review. TPAG therefore spent some time understanding and testing the assumptions underpinning GEM and the conclusions drawn from the GEM analysis. On the basis of its own deliberations, the work undertaken by the Commission and the Electricity Authority (Authority) and the largely supportive submissions from participants TPAG has concluded that there is no justification in imposing additional transaction costs on the industry in order to introduce additional locational signals through transmission pricing for economic investments in transmission assets.
- 7.1.4 The basis for reaching this conclusion is set out below.

7.2 The Generation Expansion Model (GEM)

- 7.2.1 As noted above, the Review analysis to date has considered whether there would be a benefit to transmission pricing providing enhanced locational signals for generation and load to encourage co-optimisation of investment in generation, load and transmission. The Review considered the potential benefits of further locational signalling to generation and load from two perspectives:
- (a) For signalling in respect of future economic transmission investments; and
 - (b) For signalling in respect of deferral of future reliability transmission investments.
- 7.2.2 The GEM analysis considered the potential benefits for further locational signalling to generation and load for signalling in respect of future economic transmission investments²¹.

²¹ It is likely that the different tests for investment in economic and reliability investment will be removed in the Commerce Commission's new Capex Input Methodology but this does not affect the validity of the outcomes from GEM which only address economic investments.

- 7.2.3 GEM was used to derive an estimate of the national benefit, measured as a reduction in system costs, which could be obtained from an enhanced locational price signal through transmission pricing for generators.
- 7.2.4 GEM is a long term capacity expansion planning model used for long term analyses of the New Zealand electricity sector. It is usually formulated and solved as a mixed integer programming problem, a type of optimisation model. The model yields a solution which minimises total system costs while satisfying a range of technical, economic and policy constraints. It was constructed to support the development of grid planning assumptions and grid investment approvals but has been used to support analysis of problems such as the impact of electric vehicle uptake; the impact of schemes to reduce peak demand; and the impact of renewable generation on alternative regimes for funding investment in transmission.
- 7.2.5 In this instance, to simplify the analysis, the focus is on modelling the trade-off between remote generation requiring transmission investment and generation located close to load requiring no or more limited transmission investment. Transmission investment in this context is concerned with realising the economic benefit of reduced generation costs and is accordingly categorised as economic investment. As a result GEM does not address the question of whether enhanced locational signals would support the avoidance or deferral of the costs of reliability investments.
- 7.2.6 Appendix 3 to the Stage 2 Paper provides a description of GEM and more detail on the model is available at <https://gemmodel.pbworks.com>.

7.3 The analysis undertaken using GEM

- 7.3.1 The approach to the GEM analysis was as follows:
- (a) The GEM was first configured to yield a solution representing a regime where the least cost generation options were built regardless of the interconnection costs (including DC assets) necessitated by those generation investment decisions. In this solution, locational signals from transmission pricing for interconnection assets played no role in the choice of generation.
 - (b) GEM was then configured to co-optimize interconnection and generation investment. This simulates having a pricing regime that results in co-optimised transmission and generation investment.
 - (c) The results of the two GEM solutions were compared and the difference in total system costs was taken to be an estimate of the benefit of allowing generation developers to respond to transmission pricing locational price signals.
- 7.3.2 The analysis was based on the scenarios used for the Commission's 2010 Statement of Opportunities (SOO).
- 7.3.3 This GEM analysis therefore:
- Considered only the possible benefits of locational signalling of interconnection costs in comparison to a regime where there is no locational signalling in the pricing of interconnection costs.
 - Did not consider any particular locational signalling approach, nor did it consider the implementation or transaction costs associated with any approach. The purpose was to identify whether there may be benefits that might justify further consideration of locational signalling within the transmission pricing regime.

- Did not consider the benefits or otherwise of existing locational signalling from the grid investment process, connection charging, the HVDC charge or from nodal pricing as the effects of these would have been the same in both of the two GEM solutions noted above. The connection charges are modelled in GEM as being a component of the capital expenditure associated with generation investment.

7.3.4 The results showed the benefits of allowing generation developers to respond to transmission pricing locational price signals to be positive but smaller than the margin of error within the experiments.

7.4 TPAG deliberations

7.4.1 TPAG has reviewed the analysis undertaken in Stage 1 and Stage 2 of the Review and has spent some time understanding GEM, its limitations and the factors driving its results.

7.4.2 In particular TPAG questioned whether GEM was an appropriate tool to test whether locational signals through transmission pricing might be beneficial and whether there had been sufficient validation of the model. TPAG has been assured by Authority staff that GEM “suggests sensible building patterns that are to a significant extent being played out in reality”. Submissions²² on the Stage 2 Consultation Paper outlining the GEM analysis and its conclusions were largely supportive of the Commission’s approach.

7.4.3 Not all submissions supported the GEM approach. Norske Skog agreed with the conclusion that there was limited justification in augmenting existing locational signals for economic investments but not on the basis of the GEM results. They were concerned that GEM contained too many assumptions to be a valid input into decision making. Their view was that the costs of generation investment and operation were of orders of magnitude greater than transmission investment and that transmission charges would have little bearing on generation investment decisions. In their view the use of GEM “was unnecessary to reach this common sense conclusion”.

7.4.4 In discussions TPAG members also noted that the value of transmission build is low compared to generation build, and that some technologies are highly location-specific and that these factors have a significant bearing on decision making. For example, hydro and geothermal resources cannot be relocated, and of the factors influencing a decision to invest in such generation, transmission pricing will not be a primary factor.

7.4.5 In response to submissions the Authority has undertaken additional analysis using the GEM model but with amended assumptions. These further reruns of GEM have altered results slightly but not materially enough to alter the conclusion that there is limited benefit in augmenting existing locational signals for economic investments. For instance, depending on the particular rerun being considered, total system costs may differ by as much as \$500 million (out of around \$20 billion) in NPV over a 31 year planning horizon, but the benefit of enhanced locational signals for economic transmission investments remains in the zero to \$30 million range.

7.4.6 The key assumption that has been revised in GEM, since the Stage 2 Consultation Paper was prepared, relates to the peak capacity constraints. These constraints ensure that GEM builds sufficient capacity to meet peak winter demand when there is little wind availability and in the presence of certain other contingencies, e.g. HVDC or plant outages. Upon reflection, the Authority has determined that the constraints as configured for the 2010 SOO and the analysis reported in Stage 2 were harsher than

²² See submissions from Contact, EECA, Meridian, Mighty River Power, Trustpower, Vector, Powerco and Transpower.
<http://www.ea.govt.nz/document/12634/download/our-work/consultations/transmission/tpr-stage2options/submissions/>

required. They have since been revised to operate more along the lines of the winter capacity margin. As noted above, this change causes total system costs to be reduced by a substantial amount over the entire modelled horizon. The benefit of enhanced locational signals for economic transmission investments turns out to be \$13.5 million in net present value terms – practically the same as that reported in the Stage 2 analysis.

7.4.7 A number of TPAG members were familiar with the work of the CEO Forum. The CEO Forum had also concluded there was little value in pursuing locational signals although they took a different analytical approach to that of the Commission. The coalescing of the conclusions provides further verification and comfort that the GEM approach is valid.

7.4.8 In its discussions TPAG noted that:

- (a) while there may be limited value in augmenting existing locational signals (nodal pricing, HVDC charge, deep connection and the relevant grid investment test) it is not confident that the benefits of making such a change outweighed the transaction costs of implementing the change;
- (b) the marginal benefits of such a change, as presently suggested by GEM make it difficult to justify the development of enhanced locational signals because of the associated costs;
- (c) implementing locational signals could be expected to be costly, complex and time consuming;
- (d) as with any such change it is also likely to result in unintended consequences which may be expensive to fix;
- (e) most of the potential pricing methodologies that have been considered (such as ‘tilted postage stamp’, augmented nodal pricing, load flow based approaches, etc) involve risks of unintended economic distortions and are unlikely to be fully effective in optimally coordinating transmission and generation [given the lumpy nature of the investments, the practical difficulty in coordinating the different lead time frames of transmission and generation investment].

7.4.9 In summary, TPAG concluded that there is no justification in imposing additional transaction costs on the industry in order to introduce additional locational signals through transmission pricing for economic investments in transmission assets. In forming this conclusion it drew on its own discussions, the work undertaken by the Commission and the Authority, its understanding of the GEM analysis, and the largely supportive submissions from participants.

8 Assessing Options for HVDC Charges

8.1 Introduction

8.1.1 The stage 2 consultation paper suggested that there may be material benefits in alternative HVDC charging regimes; proposed three possible alternatives to the status quo; and considered a further Capacity Rights option (proposed by NZIER) as summarised in **Error! Reference source not found..**

Table 13 HVDC Stage 2 Options

Option	Description	Rationale for Change
Status Quo	HVDC costs are met through a charge on South Island generation plant with charges based on Historical Anytime Maximum Injection (HAMI).	
HVDC Capacity Rights	The basic principle of the capacity rights approach is that generators would need to purchase capacity rights in order to use the HVDC link.	The objective would be to use a market mechanism to discover the beneficiaries of the HVDC link and to allow the market to price rights to the HVDC link.
MWh charge	HVDC charge would remain on South Island generators but would be allocated proportionately to generation in MWh rather than HAMI. The per-MWh allocation should be based on total generation over several years.	The effect of changing to a per-MWh charge would be to avoid penalising peak injections and thereby discouraging investment in peak generation or generators operating to their peak capacity.
Incentive-free allocation to SI generators	HVDC charge would remain on South Island generation plant, but would be allocated in an 'incentive-free way'.	The objective would be to find an 'incentive-free' means of allocation that did not distort operational or investment decisions.
Postage Stamp	HVDC costs would be spread broadly throughout New Zealand over load, in the same manner as interconnection assets are charged currently. Alternatively the charge could be shared with generation.	The objective would be to avoid possible distortion to competition in the new generation market.

8.2 Assessing possible generation investment inefficiency with current HVDC charges

8.2.1 The primary rationale for the options in **Error! Reference source not found.** was to find a means of allocating HVDC costs in a manner that reduced or eliminated possible distortions in the market for new generation and in the case of capacity rights used a market mechanism to identify beneficiaries and price. In order to assess the materiality of the possible distortions in the market for new generation a simplified analysis has been used to explore the cost arising from the current HVDC charge to SI generators.

8.2.2 The question is whether recovering HVDC costs from SI generators increases new entry costs in the South Island and potentially delays cheaper SI generation options relative to North Island options. The

potential inefficiency arises because recovering HVDC costs from SI generators provides an additional locational signal (discouraging new SI generation investment) which does not reflect any marginal costs since the HVDC Pole 3 investment is now committed and utilisation of the existing and new link will be fully reflected in market prices (through loss and congestion components of nodal prices in the wholesale market).

8.2.3 To the extent that there is an economic loss associated with the HVDC charge it would arise from an increase in the present value of future new generation investments with cheaper SI options delayed relative to NI options as a result of the HVDC charges.

8.2.4 Appendix F describes a simplified analysis of the possible increase in the present value of future new generation investments using the following methodology:

- A simple merit order of new generation investments is constructed by making assumptions about the capital costs, fuel costs, plant efficiencies, and operating costs of various plausible power station options;
- The new generation investments are ranked on the basis of a simple long-run marginal cost (LRMC) measure (while taking into account location factors and intermittency factors);
- A merit order without the HVDC charge is constructed and used to derive a new investment schedule and LRMC profile to cover demand growth and plant retirement out to 2050;
- The same approach is used to derive a merit order, new investment schedule, and LRMC profile while including the HVDC charge for SI generation options;
- The potential economic cost is estimated by calculating the increase in present value cost between the two scenarios.

8.3 The opportunity cost of HVDC charge to incumbent SI Generators

8.3.1 The average HVDC charge facing new entrant generators in the South Island is expected to be around \$40/kW/yr in real terms. However it can be shown that the HVDC opportunity cost for an incumbent SI generation company is between 100% and (100% - its existing HVDC cost share). Where in this range depends on the counterfactual it faces when it invests.

8.3.2 The potential counterfactuals and the impact on the largest incumbent's (Meridian with a 70% share of HVDC charges) opportunity cost are described in the appendix as counterfactual 1, 2 and 3 and are summarised in **Error! Reference source not found..**

Table 14 SI generation investment counterfactuals

Option	Description	HVDC Cost Impact
Counterfactual 1	Large incumbent generator assumes that if it invests in the SI it will displace a competitor investment in the SI	\$40/kW/yr
Counterfactual 3	Large incumbent generator assumes that if it invests in the SI it will displace a NI investment and will have no impact on a competitor investment in the SI	\$12/kW/yr (100%-70%)*40

Option	Description	HVDC Cost Impact
Counterfactual 2	In practice, the large incumbent generator will be uncertain about the outcomes and the effective HVDC cost will likely lie between Counterfactual 1 and Counterfactual 3. For the analysis it has been assumed that the cost impact is half way between the two extremes.	\$26/kW/yr

- 8.3.3 It is shown in Appendix F that the investment inefficiency from current HVDC charges is lowest under counterfactual 3 and is greatest under counterfactual 1. This is because under counterfactual 3 Meridian faces a lower effective HVDC cost and hence its projects won't be delayed as much as under counterfactual 1.
- 8.3.4 It is not possible to know which counterfactual will apply over the next 30 years. It seems likely that it will be closer to counterfactual 3 than 1 in the next few years given that SI generation options compete directly with relatively low cost NI options in a national market. However under counterfactual 3 Meridian has a substantial \$28/kW (\$40 less \$12) advantage over its SI competitors. If this was the case, Meridian is likely to increase its dominance in the SI.
- 8.3.5 Providing an artificial competitive advantage to Meridian is clearly undesirable, but it is difficult to estimate the economic cost of Meridian increasing its dominance in the SI. For this reason most reliance is placed on the analysis results for counterfactual 1 which does not give Meridian an artificial competitive advantage.

8.4 Results of possible investment inefficiency analysis

- 8.4.1 **Error! Reference source not found.** summarises the results of the simplified analysis. The analysis of the economic costs is dependent on a number of assumptions including new investment costs, fuel costs, exchange rates and other factors. For this reason sensitivity to these factors was tested and is reported in Appendix F.
- 8.4.2 **Error! Reference source not found.** suggests that the economic efficiency loss associated with the HVDC charge could be between \$19m and \$64m (average \$38m) for counterfactual 1. Although these costs are small relative to the present value of future generation investments, they are consistently positive and, arguably, should be avoided if there are no compelling reasons to retain the existing pricing structure and the cost of changing the pricing is low.

Table 15 Economic cost of HVDC charge

Counterfactual	Meridian's HVDC Opportunity Cost	Economic cost (NPV)	
		Base Case	Low gas price
1. Displaces SI generation	\$40/kW/yr	\$19-54m (average \$33m)	\$27-64m (average \$42m)

8.5 Relevance of beneficiary pays considerations

- 8.5.1 As discussed in section 6, a beneficiary pays approach can promote a more efficient transmission investment process by incentivising participants to provide quality information to the planning and investment process, and to promote commercially-driven investment where this is possible²³. However the benefits are relatively modest. This means a beneficiary pays approach is only justified where separate beneficiaries can be cheaply, clearly and objectively identified and where the allocation of costs does not cause investment or operational distortions. If the beneficiaries are too broadly spread or uncertain then the benefits of a beneficiary pays approach would not be justified by the costs.
- 8.5.2 It is good regulatory practice to apply the beneficiary pays approach consistently across the grid and over time. If a beneficiary pays approach is used to provide incentives to improve the investment planning process it is important that cost allocations to beneficiaries should reflect the value they would be prepared to pay prior to the investment (ex-ante) and not arbitrarily changed afterwards (ex-post).
- 8.5.3 An application of these considerations to the HVDC investment (pole 3) indicates that the benefits are broadly spread. The HVDC provides a mix of interconnection benefits to SI generators and NI customers in wet years, SI customers and NI generators in dry years and NI customers and SI generators in peak demand/low wind periods. It also provides system wide shared benefits from reducing losses, and by creating a national market for frequency keeping and reserves.
- 8.5.4 Beneficiaries of this investment are widely spread, and it would be difficult to clearly and robustly apportion benefits between the different groups as this depends on debateable forecasts of future scenario probabilities, resource availability and costs, carbon prices, fuel prices etc.
- 8.5.5 Application of specific beneficiary pays approach to HVDC assets would also be inconsistent in that it is not materially different to other interconnection asset investments (e.g. NIGUP) where identification of beneficiaries is clearer and more robust.
- 8.5.6 A consistent application of the application of the beneficiary pays considerations would suggest that SI generators are not the only beneficiary of the HVDC, and the benefits from attempting to allocate specific shares of benefits to the different groups of beneficiaries would be outweighed by the costs²⁴. This is explored further in the discussion below on capacity rights.

8.6 HVDC Capacity Rights

- 8.6.1 The HVDC Capacity Rights option is a relatively complex mechanism that attempts to identify the beneficiaries of the HVDC link through a market-based process whereby grid users compete for the rights to transfer energy across the link. The process would identify who would pay, and how much they would pay for, the rights. The arrangement is described in more detail in Appendix X.
- 8.6.2 The key features of the arrangements could include:
- Capacity rights could be used to allocate historical sunk costs to beneficiaries (in this case rights could be auctioned or allocated according to some historical measure of HVDC “use” or some historical measure of “benefit”).

²³ The current centrally planned and regulated process can accommodate a limited amount of commercially driven investment in the grid, postage stamping of all transmission charges tends to reduce the incentives for parties to enter these arrangements.

²⁴ Note that arguably these considerations are not particularly relevant given that pole 3 investment is committed, however the considerations are important to the extent they signal a pricing approach for future investments.

- Once allocated or auctioned capacity rights could be traded.
- If capacity rights included physical or dispatch rights, these would need to be accounted for in the spot market pricing and clearing procedures and processes.
- Capacity rights would provide holders with the financial rights to HVDC rentals and might also provide holders with physical or dispatch rights.
- Capacity rights could potentially be used to fund new capacity on the HVDC (or other interconnection assets) on a commercial basis.
- There may need to be additional mechanisms and safeguards to deal with potential system security, market power and Transpower revenue risk issues.

8.6.3 Proponents of the Capacity Rights option also point to a key benefit of the arrangement as being the identification of the beneficiaries of the HVDC link through a market-based process. They suggest that this should provide a more stable identification of beneficiaries and lead to less dispute and uncertainty about who should be funding the costs associated with the HVDC link.

8.6.4 The alternative view points out that there are several downsides associated with a capacity rights approach to the existing HVDC link as follows:

- It is most likely to have benefit if applied to new “economic” investments in the inter-connected grid – however the investment in pole 3 has been determined through a central planning process, approved by the regulator, and already committed ;
- Any new investment in the HVDC link is likely to be 20-30 years in the future;
- It would be a move away from the current open access framework – investments in generation and demand have been made on the basis of open access and it would be poor regulatory practice to move away from this approach for an existing transmission asset unless there were significant efficiency benefits;
- Because the holders of capacity rights could restrict access to transmission capacity between the islands there is a risk of short run dispatch efficiencies and the potential for exercise of short-term market power;
- [The mechanism for purchasing capacity rights could be exposed to gaming by market participants that have influence over the potential value of the capacity rights;]
- There would likely be material transaction costs associated with a capacity rights arrangement as described in appendix X;

8.6.5 It seems unlikely that the benefits of a capacity rights arrangement to the HVDC would outweigh the costs if implemented at this time. However, if there are other “economic” grid inter-connection investments that are capable of being commercially driven rather than centrally planned (without market power issues) , the Capacity Rights approach could be explored for the future. It may also be desirable to consider this approach closer to the time when new investment in the HVDC is required (20-30 years timeframe).

8.7 Change to MWh cost allocation

8.7.1 The alternative “MWh charge” option described in **Error! Reference source not found.** has been suggested as a means of reducing the possible economic distortion from charging HVDC costs to SI generators. The HVDC charge would continue to be allocated to South Island generators but allocated

proportionately to generation in MWh rather than HAMI. In other words the existing \$40/kW/yr HAMI charge would be replaced by an \$8/MWh charge while maintaining the same overall revenue.

- 8.7.2 The effect of changing to a per-MWh charge would be to avoid penalising peak injections and thereby discouraging investment in peak generation. Ideally, the per-MWh allocation would be based on total electricity generated over several years in order to avoid short-term incentives to withhold generation.
- 8.7.3 The investment inefficiency analysis has been repeated with an \$8/MWh charge. The results are summarised in **Error! Reference source not found.** which confirms that the economic distortion is likely to be lower with HVDC costs allocated to SI generators on the basis of a per MWh charge rather than HAMI.

Table 16 Economic cost of HVDC charge (\$8/MWh)

HVDC Charge to SI Generators	Economic Cost	
	Base Case	Low gas price
\$40/kW HAMI	\$19-54m (average \$33m)	\$27-64m (average \$42m)
\$8/MWh	\$10-33m (average \$22m)	\$15-36m (average \$28m)
Difference	\$9-21m (average \$11m)	\$12-32m (average \$14m)

8.7.4 The analysis suggests that the potential generation investment inefficiency would fall by between \$9m and \$32m (average \$12m) if the existing HVDC charge remained on South Island generators but was allocated proportionately to generation in MWh rather than HAMI .

8.7.5 A per-MWh charge would also have other advantages as follows:

- Reducing incentives to withhold offers of short-term generating capacity in the SI;
- Reducing incentives to mothball or retire existing peaking capacity in the SI;
- Reducing a possible distorting bias towards energy rather than capacity for new SI generation (for example in the design of new wind and hydro schemes).

8.7.6 However, a generation investment inefficiency of between \$10m and \$36m (average \$26m) would remain, and a per-MWh allocation can result in some operational dispatch inefficiencies. While there is no significant thermal generation in the SI, the MWh charge may result in slightly higher hydro spill. An experiment using the SDDP model²⁵ showed that the cost of this is relatively small (of the order of \$1m NPV over 5 years). This dispatch inefficiency could be significantly greater in the future if new base load or mid merit thermal was constructed in the SI.

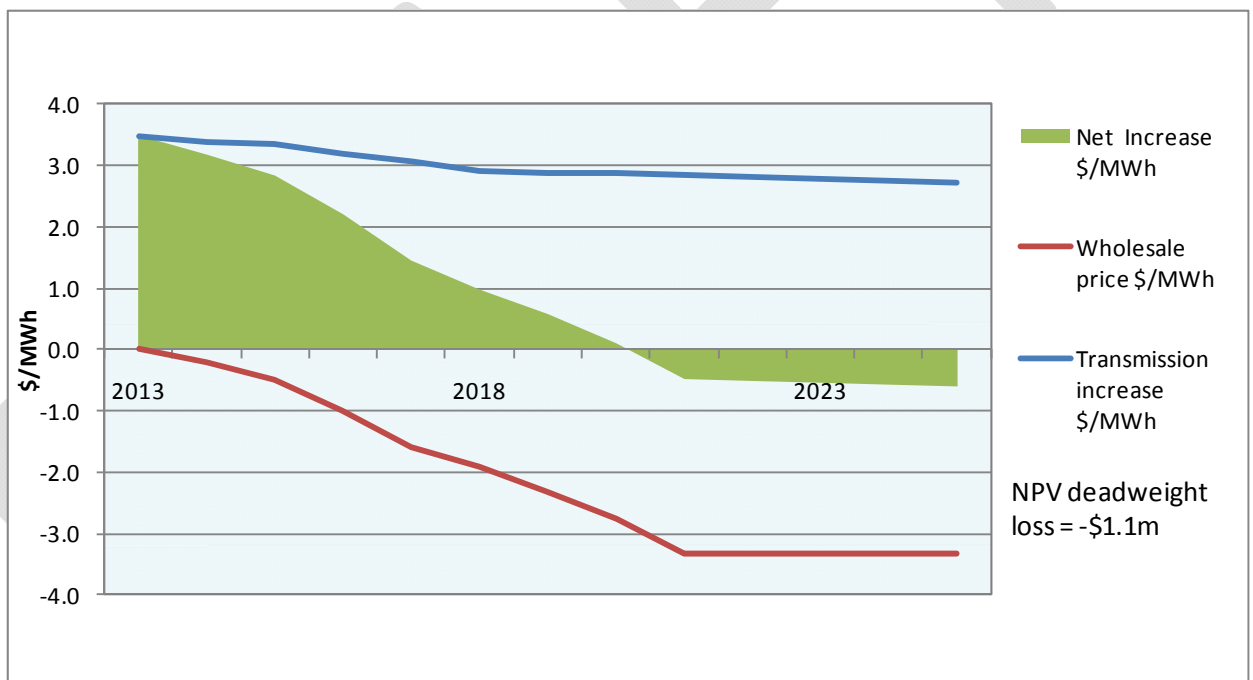
8.8 Postage Stamping the HVDC charge

8.8.1 The potential investment inefficiency identified in this section could be eliminated by recovering HVDC costs from all off-take customers or from all generators (or some mix between) through some form of postage stamp charge.

²⁵ See Appendix 4 to the Electricity Commission’s Transmission Pricing Review: Stage 2 Options, July 2010.

- 8.8.2 If the HVDC costs were allocated to off-take customers in the same manner as the existing interconnection charges (which would have low transaction costs) then Regional Coincident Demand Peak (RCDP) transmission prices to those customers would increase by \$24/kW and customers would likely see an average increase in delivered energy prices of approximately \$3.50/MWh²⁶. Other forms of postage stamping (such as recovery from all generators equally on the basis of MWh, or a 50:50 recovery from generators and customers) are likely to result in a similar short run increase in delivered energy prices²⁷.
- 8.8.3 This price increase would be immediate, but should be offset by a fall in wholesale prices in the medium term, as market prices adapt to a \$4-11/MWh drop in SI LRMV. The possible net effect over time is illustrated in **Error! Reference source not found.**
- 8.8.4 If prices were to rise by \$3.50/MWh without any countervailing drop in wholesale prices there could be a deadweight loss²⁸ associated with the price increase estimated as \$0.4m/yr²⁹ or \$3.5m net present value. However, it is more likely that there would be a countervailing drop in wholesale prices over time. If the transition is similar to that outlined in **Error! Reference source not found.** the deadweight loss would be approximately \$1.1m net present value.

Figure 4 Possible impact of a move to postage stamping HVDC charges



²⁶ This is estimated on the basis of \$147m real HVDC revenue requirement in 2013/14 over total NZ off take demand of approximately 42,000GWh.

²⁷ If HVDC charges are allocated to all generators on a MWh basis then this is likely to flow directly through into higher wholesale prices as it would be a common increase in the short run and long run marginal cost of all generation. Similarly a 50:50 split between generators and customers would result in similar total \$3.5/MWh increase, half coming from higher wholesale prices and half from higher interconnection prices.

²⁸ In economics, a deadweight loss (also known as excess burden or allocative inefficiency) is the net loss in economic welfare that is caused by a tariff or other source of distortion.

²⁹ \$3.50/MWh represents a 2% increase in the national average delivered electricity price of \$170/MWh (MED 2009) which would reduce demand by 0.4% or 200GWh assuming elasticity of -0.25. The deadweight loss = $\$3.50 \times 200 / 2 = \$400,000/\text{yr}$.

- 8.8.5 This potential deadweight loss might be offset if there are efficiency gains from higher RCDP charges deferring transmission reliability investments³⁰.
- 8.8.6 The cost of implementing a change to postage stamp charges for the HVDC should be relatively insignificant since existing cost allocation procedures could be used. Thus overall the economic costs (including any deadweight costs) of moving to postage stamp charges for the HVDC should be small.
- 8.8.7 The extent and size of the overall value changes in the sector are difficult to estimate with any precision because of the offsetting impacts, but are likely to be as follows:
- SI generators: lower transmission costs offset by lower medium term wholesale prices – could be net positive or negative in medium term;
 - NI generators: lower medium term wholesale prices – likely to be net negative;
 - SI customers: higher transmission costs offset by lower medium term SI wholesale prices (reflecting lower long run marginal cost of SI generation) – could be net negative or positive in medium term;
 - NI customers: higher transmission costs offset by lower medium term NI wholesale prices (also reflecting, although not so directly, the lower long run marginal cost of SI generation)– likely to be net zero or negative.
- 8.8.8 While medium term value impacts are likely to be relatively small, it is recognised that postage stamping results in a significant immediate and certain transfer of value to SI generators from NZ customers offset by future and uncertain wholesale price effects.
- 8.8.9 Although value transfers associated with a change in pricing are not directly included in measures of allocative inefficiency, they can indirectly give rise to economic costs in the regulatory process.
- 8.8.10 The application of good regulatory practice suggests that consistency and stability in pricing is important and changes which involve wealth transfers should be avoided unless there are significant efficiency benefits.
- 8.8.11 Moving to a MWh allocation of HVDC charges leaves approximately \$10-36m (\$25m average) NPV generation investment distortions, but would avoid significant value transfers. It is debateable whether the benefit of removing this residual distortion is significant enough to justify a move to full postage stamping with its short run value impacts. It would be better to find an alternative option which eliminates the residual distortions and minimises the value impacts.
- 8.9 Possible transition to Postage Stamping the HVDC charge**
- 8.9.1 A transitional approach which retains the historical allocation of old HVDC costs to SI generators, and moves to postage stamping for the new pole 3 investments may have merit. This would be consistent with good regulatory practice which seeks to promote consistency and stability in pricing. In TPAG's

³⁰ This potential efficiency gain has not been estimated, but would involve an assessment of the size of the additional price signal to encourage demand management relative to the value of delaying transmission reliability investments. If the signal from the current RCDP charges is too low then there would be benefit from an increase. However if the signal from the current charges is approximately correct then there would be no additional benefit. In this case it may be sensible to recover HVDC charges from customers via a MWh rather than RCDP charge to avoid providing an excessive signal to manage peak demand.

view this approach would enable the removal of the residual distortions described above without creating significant value transfers.

8.9.2 A possible transition from the status quo to allocating HVDC costs to off-take customers on a postage stamp basis could be provided as follows:

- The current SI generators continue to meet the HVDC charges associated with the old HVDC assets (in the same proportions as for the status quo) with the charges phased out over a transitional period;
- New SI generation projects are not required to pay HVDC charges;
- The residual HVDC costs (the cost of pole 3 development and any costs arising from the transition) are allocated to off-take customers using a postage stamp charge.

8.9.3 Ideally the allocation of the existing HVDC charges between existing SI generators over the transitional period would be fixed in advance so as to remove any incentives that could distort behaviour and create inefficiencies. This could be done, for example, on the basis of historical share of HVDC charges³¹.

8.9.4 The transition could be designed to compensate for the expected net effect of postage stamping the HVDC costs as illustrated in **Error! Reference source not found.** This would have the effect of eliminating any material deadweight loss associated with the change in HVDC charges.

8.10 Summary of HVDC Options

8.10.1 **Error! Reference source not found.** summarises the advantages and disadvantages of the HVDC options considered in this discussion paper.

Table 17 Advantages and disadvantages of HVDC options

Option	Pros	Value	Cons	Value
Status Quo	<ul style="list-style-type: none"> • Consistent with charging practice over last [11] years 		<ul style="list-style-type: none"> • Distorts short-term operation in SI • Deters investment in SI peaking capacity • Distorts incentives for new generation between NI/SI and provides an artificial competitive advantage for Meridian • Inconsistent application of beneficiary pays principle 	<p>Low</p> <p>\$0-25m</p> <p>\$38m</p> <p>?</p>

³¹ It should be easier to develop a practical and acceptable “incentive-free” allocation of “old” HVDC costs during a transitional period. Such an arrangement could also factor in an adjustment to recognize the potential loss of HVDC rental revenues associated with the location hedging proposal.

Option	Pros	Value	Cons	Value
Capacity Rights	<ul style="list-style-type: none"> • Should help to identify beneficiaries of HVDC transmission • Introduces an approach that could have useful application on other transmission links • Enables the market to determine a price for rights to HVDC link. 	<p>?</p> <p>?</p>	<ul style="list-style-type: none"> • Possible economic loss from constrained dispatch • Significant implementation issues and costs and relatively high transaction costs • Shifts the goalpost – existing investments made under open access regime • Open to possible gaming by some market participants • Possible revenue shortfall for Transpower 	<p>?</p> <p>high</p> <p>?</p>
MWh Charge	<ul style="list-style-type: none"> • Reduces short-term operational distortion in SI • Reduces the deterrent for investment in SI peaking capacity • Reduces the distortion of incentives for new generation between NI/SI 	<p>Low</p> <p>\$0-25m</p> <p>\$12m</p>	<ul style="list-style-type: none"> • Some remaining NI/SI new generation distortion and still provides an artificial competitive advantage for Meridian • Minor remaining dispatch distortion which could increase if there is SI thermal • Inconsistent application of beneficiary pays principle for pole 3 	<p>\$26m</p> <p>\$1-?m</p> <p>?</p>
Postage Stamp	<ul style="list-style-type: none"> • Eliminates short-term operation distortion in SI • Eliminates the deterrent for investment in SI peaking capacity • Eliminates the distortion of incentives for new generation between NI/SI and btw SI gens 	<p>Low</p> <p>\$0-25m</p> <p>\$38m</p>	<ul style="list-style-type: none"> • Small deadweight loss from price shock • Value shift in transition is inconsistent with good regulatory practice 	<p>\$0-3m</p> <p>?</p>
Postage Stamp Transition	<ul style="list-style-type: none"> • Eliminates short-term operational distortion in SI • Eliminates the deterrent for investment in SI peaking capacity • Eliminates the distortion of incentives for new generation between NI/SI and btw SI gens 	<p>Low</p> <p>\$0-25m</p> <p>\$38m</p>		

9 Assessing Options for Deferring Reliability Investments

9.1 Introduction

9.1.1 To be drafted

9.2 Regional Coincident Peak Pricing

9.2.1 To be drafted

9.3 Bespoke Pricing Options

9.3.1 To be drafted

9.4 Flow Tracing Options

9.4.1 To be drafted

9.5 Transmission Alternatives Regime

9.5.1 Commerce Commission....

9.6 Submissions on Reliability Investments

9.6.1 To be drafted

9.7 Conclusion

9.7.1 Defer Consideration...

9.7.2 To be drafted

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10 Assessing other Options

10.1 Connection

10.1.1 To be drafted

10.1.2 Defer consideration

10.2 Static Reactive Compensation

10.2.1 New group

10.2.2 Defer consideration

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- 11 Preferred Option for TPM**
- 11.1 Description of Preferred TPM**
 - 11.1.1 To be drafted
- 11.2 Cost-Benefit Analysis**
 - 11.2.1 To be drafted
- 11.3 Applying the Evaluation Criteria**
 - 11.3.1 To be drafted

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12 Conclusion

12.1 Outcomes from Assessment

12.1.1 To be drafted

12.2 Recommended TPM Guidelines

12.2.1 To be drafted

12.3 Issues for Submission

12.3.1 To be drafted

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Appendix A List of questions

A.1.1 To be drafted

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Appendix B Submissions Summary

B.1.1 To be drafted

DRAFT

Appendix C Impact of regulatory Change

C.1.1 To be drafted

DRAFT

Appendix D Postage Stamp Pricing

D.1.1 To be drafted

DRAFT

Appendix E Transpower Revenue Requirement

E.1.1 To be drafted

DRAFT

Appendix F Impact of HVDC Cost Allocation on Investment in new Generation

Methodology for assessing possible investment inefficiency

- F.1 This appendix attempts to establish whether there is a potential economic cost arising from the recovery of HVDC costs from SI generators. To the extent to which there is an economic cost, this would arise from the investment inefficiency caused by the HVDC cost recovery potentially delaying cheaper SI options relative to North Island options of the next 30 years.
- F.2 The potential investment inefficiency arises from the fact that the HVDC cost recovery provides an additional locational signal (discouraging new SI generation investment) which does not reflect any marginal costs since the HVDC investment is committed and utilisation of the existing and new link will be fully reflected in market prices (through loss and congestion components of nodal prices in the wholesale market)³².
- F.3 This appendix describes a simplified analysis of the possible increase in present value of future new generation investments (arising from the HVDC charge) using the following methodology:
- A simple merit order of new generation investments is constructed by making assumptions about the capital costs, fuel costs, plant efficiencies, and operating costs of various plausible power station options³³;
 - The new generation investments are ranked on the basis of a simple long-run marginal cost (LRMC) measure including capital recovery, fixed and variable operating costs, fuel and ETS costs, and approximate location factors (reflecting marginal losses) and intermittency factors³⁴;
 - A merit order without the HVDC charge is constructed and used to derive a new investment schedule and LRMC profile to cover demand growth and plant retirement out to 2050;
 - The same approach is used to derive a merit order, new investment schedule, and LRMC profile while including the HVDC charge for SI generation options;
 - The potential economic cost is estimated by calculating the increase in present value cost between the two scenarios for a base case scenario and for one with a lower gas price³⁵.

³² The additional locational signal may possibly reflect a true marginal cost beyond 30 years when another HVDC investment may be required to either upgrade the capacity of the link to maintain the capacity when the existing pole 2 reaches the end of its economic life.

³³ This analysis uses plausible assumptions developed from a combination of sources including the Electricity Commission (used in GEM analysis) and MED.

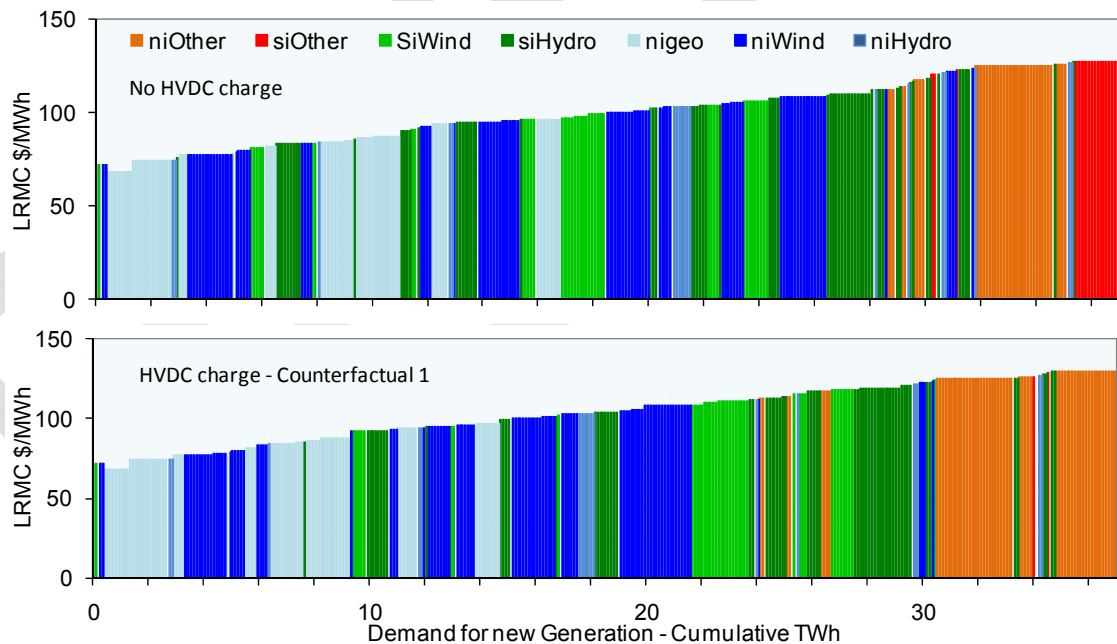
³⁴ The intermittency factors take into account that different projects achieve different weighted-average prices from time-weighted prices.

³⁵ The base case scenario assumes that gas supply remains limited, and there is a \$40/t carbon price, a \$13/GJ gas price, \$4.5/GJ coal price in real 2010 terms. Under this scenario existing CCGT capacity is maintained and most new capacity is geothermal, hydro or wind over the next 30 years. The low gas cost scenario is based on a significant new gas discovery at \$8/GJ which would support some additional CCGT gas plant beyond 2025.

Constructing the merit order

- F.4 There is a merit order of future new generation projects that are available to meet the growing demand for electricity. It is difficult to know exactly what this merit order is because it depends on a whole range of factors (capital and fuel prices, resource availability, exchange rates, and discount rates, for example). Although there are many factors that influence the sequence of development for new generation, it is reasonable to assume that new projects generally proceed according to a rough order of cost with the cheapest projects proceeding first.
- F.5 For this analysis it is not especially important what the exact merit order is. What is important is the potential cost of changing the merit order through the application of HVDC charges on SI generation projects.
- F.6 Figure 5 illustrates the two different merit orders used in this analysis, highlighting that a range of geothermal and wind projects appear to provide the cheapest development options³⁶. Note that 10 TWh represents approximately 25% of today's annual electricity demand.
- F.7 The potential impact of the HVDC charge on the merit order is illustrated by the change in the chart "No HVDC charge" to "HVDC charge – Counterfactual 1". Note that, in this example, a number of SI wind and hydro projects are delayed as a result of the HVDC charge.

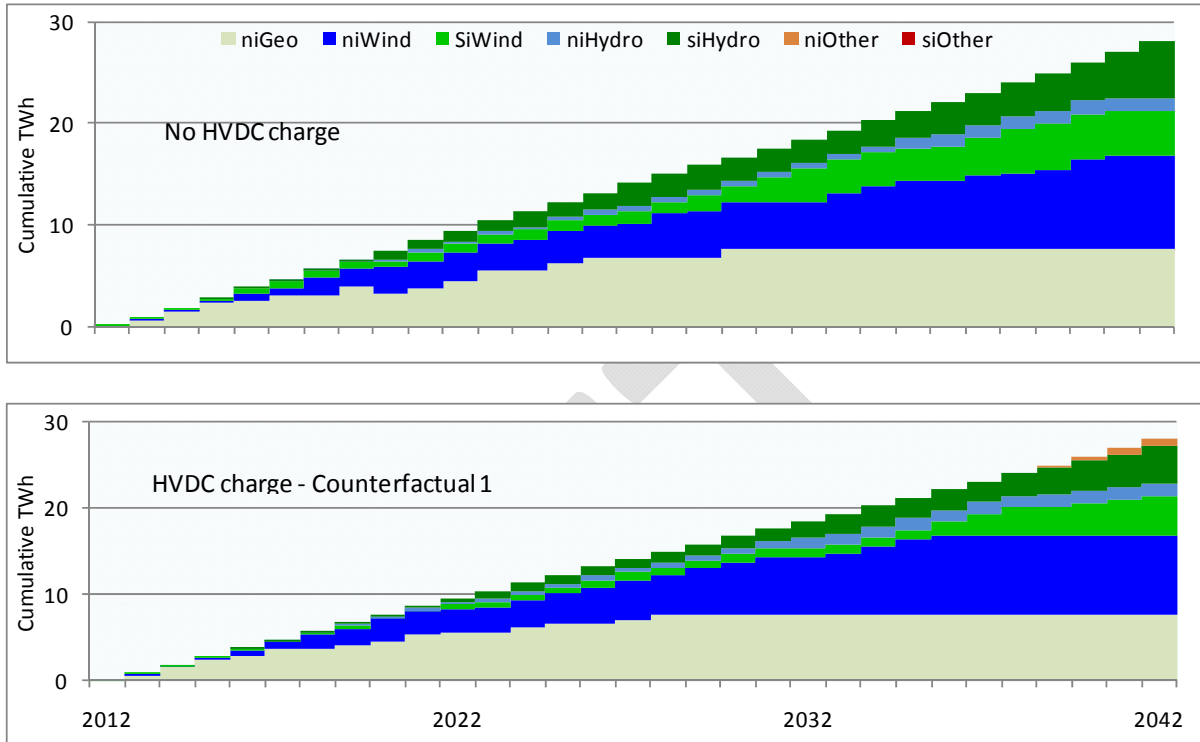
Figure 5: Illustrative merit order of new generation projects (\$/MWh)



- F.8 This is further highlighted in Figure 6 which illustrates the timing of new generation under the two scenarios. The impact of the HVDC charge in this example is to defer some SI hydro and wind developments relative to NI projects.

³⁶ The long run marginal costs have been estimated using an assessed weighted-average-cost-of-capital (WACC) of 7% real post-tax. This reflects a typical commercial rate of return required by generators.

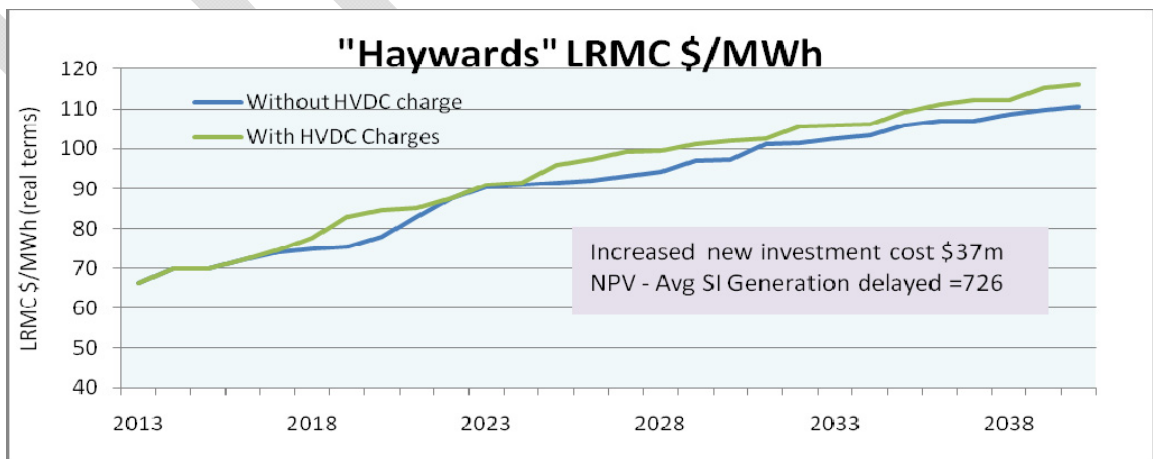
Figure 6 Illustrative impact on timing of investment



F.9 Figure 7 illustrates the potential impact on the LRMC curve which tends to feed into wholesale electricity prices. The LRMC curve is derived at the Haywards location by referring all projects to that point using the assumed average location factor for each project.

F.10 Note that in this example LRMC is up to \$8/MWh higher in some years. This would likely flow through to wholesale electricity prices and possibly impact upon NI/SI price differentials.

Figure 7 Impact on the LRMC curve



Sensitivity analysis

- F.11** An estimate of the economic cost has been determined by calculating the difference in the net present value of investment between the two scenarios over 30 years using a 9% real pre tax discount rate³⁷.
- F.12** The analysis assumes that the average HVDC charge under the existing price structure is \$40/kW/yr in real 2010 dollar terms³⁸.
- F.13** The analysis of the economic costs is also dependent on a number of assumptions including new investment costs, fuel costs, exchange rates and other factors. In particular, the economic cost estimate is sensitive to the relative cost and outputs of particular individual projects which are only known to within $\pm 30\%$. To account for these 10 separate cases were evaluated with individual project costs being randomly varied by $\pm 20\%$ around a generic capital cost for each general class of investments (geothermal, wind, hydro thermal etc).
- F.14** For this reason sensitivity to these factors was tested and reported in Table 18.

Table 18 economic Cost - Sensitivity Analysis

HVDC Charge \$40/kW	Economic Cost \$m PV	
Sensitivity	Base Case	Low Gas cost Scenario
Current Exchange rates	\$21m	\$40m
Long run Exchange Rates	\$19m	\$31m
Random Capex 1	\$42m	\$42m
Random Capex 2	\$44m	\$56m
Random Capex 3	\$30m	\$33m
Random Capex 4	\$35m	\$42m
Random Capex 5	\$31m	\$49m
Random Capex 6	\$54m	\$64m
Random Capex 7	\$21m	\$29m
Random Capex 8	\$20m	\$27m
Random Capex 9	\$47m	\$56m
Random Capex 10	\$37m	\$38m
Average	\$33m	\$42m

³⁷ Note that a 9% real pre-tax rate is approximately consistent with the 7% real post-tax rate used to assess the commercial return typically required for new generation.

³⁸ In reality the HVDC charge (in real 2010 terms) is expected to be around \$45/kW/yr in 2013 and then fall to around \$40/kW/yr by 2020, and then continue to fall in real terms as a result of the accounting rules used in setting the revenue requirement. Previously parties paying HVDC charges received HVDC rentals (valued at around \$5/kW/yr). The value of these rentals has not been accounted for in the analysis as it is expected to decline when Pole 3 is commissioned and it is not clear that payers of HVDC charges will continue to receive these rentals in the future.

F.15 The sensitivity analysis was undertaken for a \$40/kW/yr HAMI charge suggests an economic cost in a band of \$19m to \$64m (average \$38m).

Change from HAMI cost allocation

F.16 The alternative MWh charge option described in **Error! Reference source not found.** has been suggested as a means of reducing any possible economic distortion from charging HVDC costs to SI generators. Recovering the same revenue over all SI generation could be achieved with an \$8/MWh charge instead of a \$40/kW HAMI charge.

F.17 The investment inefficiency analysis has therefore been repeated with an \$8/MWh charge. The results are summarised in Table 19 which confirms that the economic distortion is likely to be lower with HVDC costs allocated to SI generators on the basis of a per MWh charge rather than HAMI³⁹.

Table 19 Economic cost of HVDC charge (\$8/MWh)

HVDC Charge	\$8/MWh	Economic Cost \$m PV		Difference from HAMI	
		Base Case	Low Gas cost	Base Case	Low Gas cost
Current Exchange rates		\$16m	\$26m	-\$5m	-\$15m
Long run Exchange Rates		\$12m	\$24m	-\$7m	-\$7m
Random Capex 1		\$27m	\$30m	-\$15m	-\$13m
Random Capex 2		\$33m	\$35m	-\$10m	-\$21m
Random Capex 3		\$24m	\$26m	-\$6m	-\$7m
Random Capex 4		\$24m	\$35m	-\$12m	-\$7m
Random Capex 5		\$21m	\$27m	-\$9m	-\$22m
Random Capex 6		\$29m	\$32m	-\$25m	-\$32m
Random Capex 7		\$16m	\$23m	-\$5m	-\$6m
Random Capex 8		\$10m	\$15m	-\$10m	-\$12m
Random Capex 9		\$32m	\$36m	-\$16m	-\$19m
Random Capex 10		\$24m	\$27m	-\$13m	-\$11m
Average		\$22m	\$28m	-\$11m	-\$14m

F.18 The reason why the economic cost is lower in this case is that the inefficiency mainly relates to delays in SI wind and hydro and these projects typically have capacity factors in the order of 35-50%. A HAMI allocation would imply a \$10-\$13/MWh disadvantage for SI projects, whereas this is reduced to \$8/MWh under a MWh allocation.

³⁹ Note that there are additional economic distortions associated with the HAMI price structure relating to the incentives it provides to withhold capacity from the SI market and to discourage incremental SI peaking capacity. These are not quantified in this appendix, but were estimated to be \$0-25m in earlier work carried out by the Electricity Commission (Appendix 4 to the Consultation paper on Stage 2 Options, July 2010).

Opportunity cost of HVDC charges to Incumbent SI Generators

- F.19 The analysis above is based on a \$40/kW/yr or an \$8/MWh HVDC charge facing new entrant generators in the South Island. However this may not be equal to the opportunity cost for incumbent generators.
- F.20 The opportunity cost of the HVDC charges for an incumbent SI generator depends on both its share of the HVDC charges and the “counterfactual”. The opportunity cost can be lower for parties who pay a high share of the costs. This is because total HVDC charges are fixed and any new investment in SI generation will simply result in a reallocation of these charges between the existing payers and new generators. A completely independent new SI generator will see the full HVDC cost for its new generation (\$40/kW/yr), but all the incumbents will benefit from a reduction in their share of the costs. It can be shown⁴⁰ that the HVDC opportunity cost for an incumbent investing in the South Island is between 100% of the full HVDC cost (\$40/kW/yr) and $(1-\text{share})^{41}$ times the full HVDC cost depending on the investment counterfactual.
- F.21 The investment counterfactuals relate to the impact of an incumbent’s new SI generation investment on the investment plans of its competitors. The impact of the different counterfactuals on Meridian Energy’s (the largest incumbent) HVDC opportunity cost is summarised in Table 20.

Table 20 SI generation investment counterfactuals and Impact on Meridian Energy

Option	Description	Meridian’s HVDC opportunity cost
Counterfactual 1	Large incumbent generator assumes that if it invests in the SI it will displace a competitor investment in the SI	\$40/kW/yr
Counterfactual 3	Large incumbent generator assumes that if it invests in the SI it will displace a NI investment and will have no impact on a competitor investment in the SI	\$12/kW/yr = $(1-70\%)*40$
Counterfactual 2	In practice, the large incumbent generator will be uncertain about the outcomes and the effective HVDC cost will likely lie between Counterfactual 1 and Counterfactual 3. For the analysis it has been assumed that the cost impact is half way between the two extremes.	\$26/kW/yr

- F.22 Table 21 summarises the results of the simplified analysis and suggests that the average economic efficiency loss associated with the HVDC charge could be between \$24m and \$42m. Note that the loss appears to be highest for counterfactual 1 (where investment by the incumbent displaces other SI generation) and lowest for counterfactual 3 (where investment by the incumbent displaces NI

⁴⁰ For example see Appendix to Q5 of Norske Skog submission on Transmission Pricing Review (Sep 2010).

⁴¹ This is the share of the total HVDC costs that a particular SI incumbent is paying prior to making a new investment in the South Island. Typically this would be around 70% for Meridian, 22% for Contact, 6% for Genesis and 2% for TrustPower.

generation). This is because, under counterfactual 3, Meridian faces a lower effective HVDC cost and hence its projects won't be delayed as much as under counterfactual 1⁴².

Table 21 Economic cost of HVDC charge

Counterfactual	Meridian's HVDC opportunity cost	Average Economic cost (NPV)	
		Base Case	Low gas price
1. Displaces SI generation	\$40/kW/yr	\$33m (\$19-\$54m)	\$42m (\$27-\$64m)
2. Intermediate	\$26/kW/yr	\$28m (\$15-\$45m)	\$35m (\$23-\$51m)
3. Displaces NI generation	\$12/kW/yr	\$24m (\$14-\$43m)	\$30m (\$18-\$50m)

- F.23 However, note that under counterfactual 3 Meridian has a \$28/kW (\$40 less \$12) advantage over other SI competitors and, if this was the case, it could lead to Meridian increasing its dominance in the SI. This reduction in competition would likely lead to additional efficiency losses not accounted for in this analysis.
- F.24 It is not possible know which counterfactual will apply over the next 30 years. It seems likely that it will be closer to counterfactual 3 than 1 in the short run given that SI options are competing directly with relatively low cost NI generation options (e.g. geothermal). Once the relatively cheap NI geothermal options have been fully developed, counterfactual 2 is more likely as SI generation options (such as wind and hydro) compete with similar cost projects in the NI. Counterfactual 1 would apply if there is a band of SI generation options which are all clearly cheaper than the lowest cost NI options, or there has been so little investment in the SI that SI reliability is threatened and new capacity is required in the SI.
- F.25 Providing an artificial competitive advantage to Meridian is clearly undesirable, but it is difficult to estimate the economic cost of Meridian increasing its dominance in the SI. For this reason most reliance is placed on the analysis results for counterfactual 1 which does not provide Meridian an artificial competitive advantage.

Conclusion from Analysis

- F.26 The analysis in this appendix suggests that :

⁴² Note that the Electricity Commission carried out experiments to estimate the economic cost of generation investment inefficiencies arising from the HVDC charge as outlined in Appendix 4 of the Transmission Pricing Review: Stage 2 Options, July 2010. This was derived using the GEM model and resulted in cost estimates of \$6-36m (average \$16m). These results are broadly similar, but are not strictly comparable with this updated analysis as this earlier work used a lower HVDC cost of \$30/kW/yr, assumed counterfactual 3 only, used uncommercial discount rates to rank generation projects, imposed higher capacity margins than the standard and used outdated capital cost estimates and efficiencies for some plant types.

- Charging HVDC costs to all SI generators with a HAMI allocation is likely to create an investment inefficiency of the order of \$19-64m (average \$38m) in net present value terms over the next 30yrs;
- The costs could be \$8-10m lower if the large SI incumbent faced counterfactual 2 or 3, but if this is the case there is likely to be an additional inefficiency resulting from the artificial competitive advantage to Meridian and the likely increase in its dominance in the SI;
- The investment inefficiency would fall to the order of \$10-36m (average \$26m) in net present value terms if the HAMI charge was replaced with a per MWh charge.

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References

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