Transmission Pricing Advisory Group

Transmission pricing discussion paper

Version 3: for TPAG review

April 2011

Note: This paper includes 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 have yet to be drafted
- the paper contains some editing comments highlighted items to indicate further editing is required

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.

669651-9

Executive summary

Overview of progress on sections

	Section	Progress
1 **2** **3**	Introduction Background Summary of earlier stages of the review	These drafts were provided to TPAG meeting 4 and meeting 5. Some amendments have been made to these sections in particular to reflect the Electricity Authority decision on the Code amendment proposal for the transmission pricing regulatory framework. Some parts have been moved to this section from the analysis framework section for example the summary of the impact of the regulatory change on the work to date.
4	Analysis framework	**For discussion at TPAG meeting 6, 14 April** This section is an amalgamation of two sections that were previously the analysis framework and approach to assessment. The redrafting reflects the agreement from TPAG to consolidate the sections and to dispense with the evaluation criteria.
5	Location-based price signals	This is based on the 'GEM analysis paper' provided to TPAG meeting 3. TPAG requested that this be amended for style reasons, but this has not yet been done.
6	Assessing options for HVDC charges	**For discussion at TPAG meeting 6, 14 April** This section is has been amended following TPAG comment.
10	Assessing other options	To be drafted – may include assessment of deep connection issues and static reactive compensation
11	Preferred option for TPM	To be drafted
12	Conclusion	To be drafted
	Appendices	The appendix on the impact of HVDC cost allocation on investment in new generation has been redrafted to take out the conclusions and stick solely to the analysis.

Glossary of abbreviations and terms

[insert text]	[insert text]

Contents

Tables

Figures

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 reference[2] 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 accepted by the Authority Board, the Authority will publish an Issues Paper and draft guidelines for the TPM.

[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/

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.

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 2.3 below). The Authority sets guidelines for the development of, and makes a determination on 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 role of the TPM in the context of the existing regulatory and market environment is summarised in the table below.

Table 2 The Transmission Pricing Methodology in context

Consideration	Description
Transpower's transmission network is regulated	• Central planned and separate Commerce Commission regulation of new investment in transmission. o 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	• 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 o 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.

2.1.4 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 administration and ongoing development 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 Act repealed those parts of the Electricity Act 1992 which established the Electricity Commission and market governance arrangements including the Electricity Governance Rules (EGRs). The Authority is an independent Crown Entity.

2.3.2 The objective of the Authority, as set out 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 (Code[3]) replaced the EGRs and 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.

[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.

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 3 and are available in full from the Authority's website[4]. These documents are relevant 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 3 The Authority's foundation documents

Foundation document	Purpose and content
Interpretation of the Authority's statutory objective	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* 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.
Consultation Charter	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: (a) amending the Code; and (b) consulting on proposed amendments to the Code. For the sake of clarity, the Authority has divided the consultation charter into two parts: (a) Part 1 relates to processes for amending the Code; and (b) Part 2 relates to processes for consulting on proposed amendments to the Code. 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.
Charter about Advisory Groups	The Act requires the Authority to establish one or more advisory groups[5] to provide independent advice to the Authority on the development of the Code and on market facilitation. The Act requires the Authority to make, and make publicly available, a charter on: (a) how it will establish and interact with the advisory groups; and (b) when and how it will consult advisory groups on material changes to the Code; and (c) how advisory groups must operate, including provisions concerning procedure.

2.3.5 The provisions in the Code relating to transmission pricing and the development of the TPM (subpart 4 of Part 12) were largely carried over from section IV of part F of the EGRs. Pre 1 November 2010 the

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

[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.

regulatory framework for the TPM was governed by the Electricity Act 1992 and the EGRs. This required that the preferred option:

a) was consistent with the Commission's principal objectives and specific outcomes set out in section 172N of the Electricity Act 1992[6];

b) was consistent with the relevant objectives and outcomes in the Government Policy Statement on Electricity Governance;

c) was consistent with the pricing principles set out in rule 2 of section IV of part F of the EGRs;

d) took into account practical considerations, account transaction costs and the desirability for consistency and certainty for both consumers and the industry; and

e) was consistent with any determination made under Part 4 of the Commerce Act 1986.

2.3.6 The establishment of the Authority with a new statutory objective led to a reconsideration of the decision framework that underpinned previous decisions about the TPM. As part of a separate Review workstream, the Authority reviewed the ongoing relevance of the transmission pricing principles carried over to the Code. The Authority's analysis, supported by submissions from Stage 2 of the Review, concluded that the interface between its statutory objective, the guidelines and the pricing principles was complex and unwieldy and, combined with the ongoing lack of consensus around the pricing principles, was a demonstrable regulatory failure. Following a formal Code amendment proposal in February 2011 and consideration of submissions in response, the Authority concluded that the pricing principles and the related interpretation clauses (clauses 12.79 and 12.80) should be removed from the Code. The amendments will come into effect on 1 June 2011. The analysis in this paper anticipates this Code change as the Authority has made and published its decision. It would be unproductive to assess TPM options against criteria which will not be relevant by the time decisions are made.

2.3.7 The regulatory framework for the development of the guidelines and the TPM post 1 June 2011 will consist of:

a) relevant provisions of the Act, where the new statutory objective is of particular relevance;

b) subpart 4 of part 12 of the Code which addresses the process by which the TPM and guidelines are developed and approved;

c) ensuring consistency with any determination made under Part 4 of the Commerce Act 1986; and

d) potentially statements of government policy.

2.3.8 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 3 above), specifically the Code Amendment Principles are also relevant to the TPM decision framework.

[6] The Commission's principal objectives in section 172N of the Electricity Act 1992 required the Commission to:

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

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

2.4 Impact of Regulatory Change on Work Undertaken to Date

2.4.1 TPAG has noted that the Review was commenced by the Commission within the framework of the Electricity Act 1992 and the EGRs and is now being advanced by the Authority within the framework of the Electricity Industry Act 2010 and the Code.

2.4.2 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 are consistent with the statutory objectives of the Authority.

2.4.3 TPAG considered the impact of the change in statutory objective on the work undertaken to date by the Commission. TPAG's conclusions[7] 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.
- 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.

---

[7] The full TPAG paper is available at http://www.ea.govt.nz/document/13322/download/our-work/advisory-working-groups/tpag/tpag-meeting-28-march-2011/

- 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.

2.5 Review process and timetable

2.5.1 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 3 of this paper.

2.5.2 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.

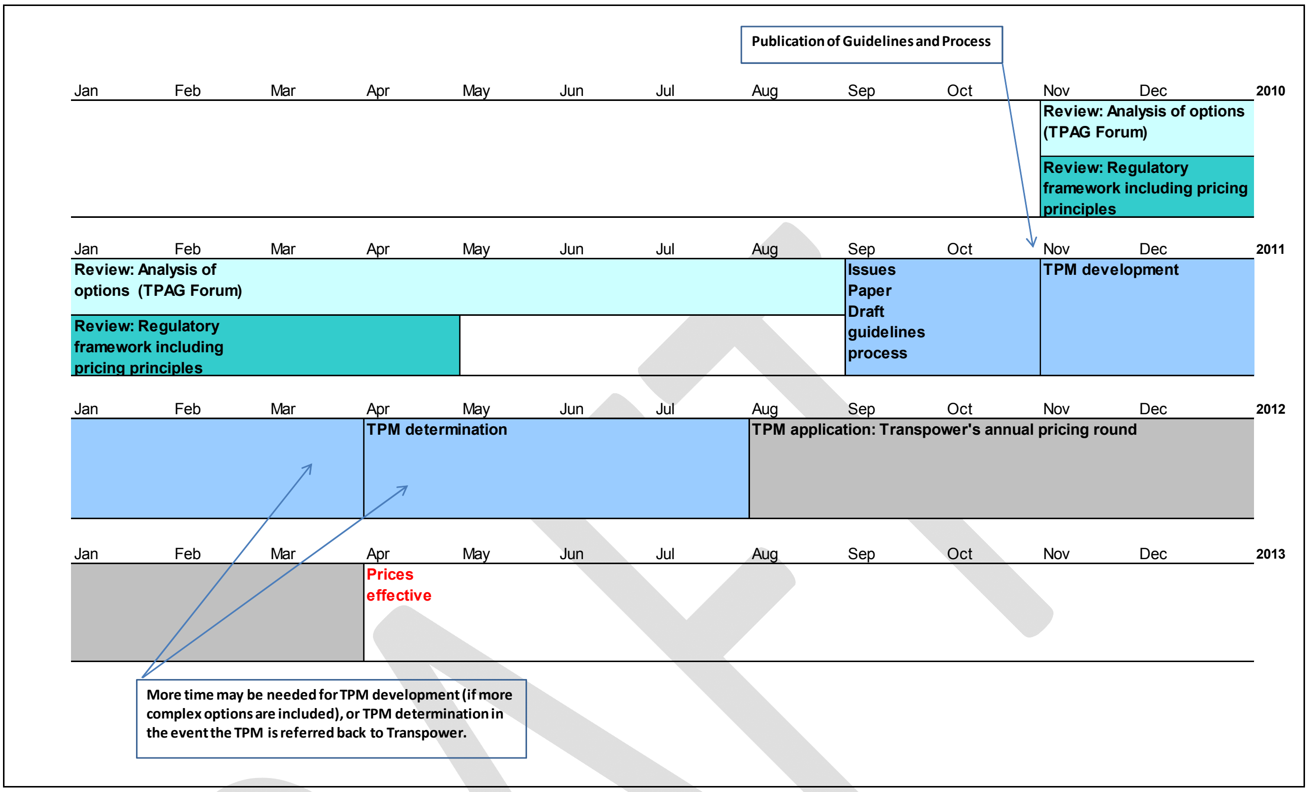
2.5.3 The indicative timeline is shown in Figure 1 below. There are three phases to this work:

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).

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



2.5.4 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 4 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.

2.5.5 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 4 Estimate timeframes following publication of the Issues Paper

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 *Note: Transpower may require more time for TPM development*
TPM determination	Authority: • 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 *Note: More time may be needed if the TPM is referred back to Transpower*
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 provided initial estimates for some options from Stage 2 of the Review.	Estimated timeframe of up to two years, depending on the nature and complexity of the option adopted and the implementation approach	
TPM application	Transpower develops, audits and publishes prices.	12.96 to 12.101	Start Aug of year preceding pricing year

2.5.6 As can be seen, the timeframes are very tight if there are to be changes to the TPM in place for April 2013. There are several key assumptions underpinning the indicative timeframes presented here. In particular:

- 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 allowance 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.

2.5.7 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) **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 2011[8]. The development of the locational price risk is also linked to the proposed introduction of scarcity pricing, discussed in the next bullet.

b) **The Authority's scarcity pricing project**. This project is designed to address concerns that spot prices are likely to be suppressed when non-price mechanisms (such as requests for voluntary conservation by consumers) are used to curtail demand. It is important during supply emergencies that spot prices provide efficient signals, otherwise efficient investment in last resort generation and/or voluntary demand-side response will be undermined. In April 2011 the Authority published a consultation paper setting out its proposed set of scarcity pricing measures designed to induce higher levels of generation and/or price responsive demand. Efficient price signalling for investment in transmission, generation and demand is one of several fundamental aspects of TPAG's assessment framework for TPM options (refer section XX], and the implications of the scarcity pricing regime are relevant to TPAG's consideration, particularly in its development of the appropriate counterfactual against which to assess options.

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 2010[9]. 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 preliminary views on Capex IM. It is due to publish its Draft Determination in June/July 2011.

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. Appendix [XX] contains a more detailed description of the various transmission pricing options considered during the course of the Review.

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 1) 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)

[8] 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.

[9] These determinations are subject to appeal.

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

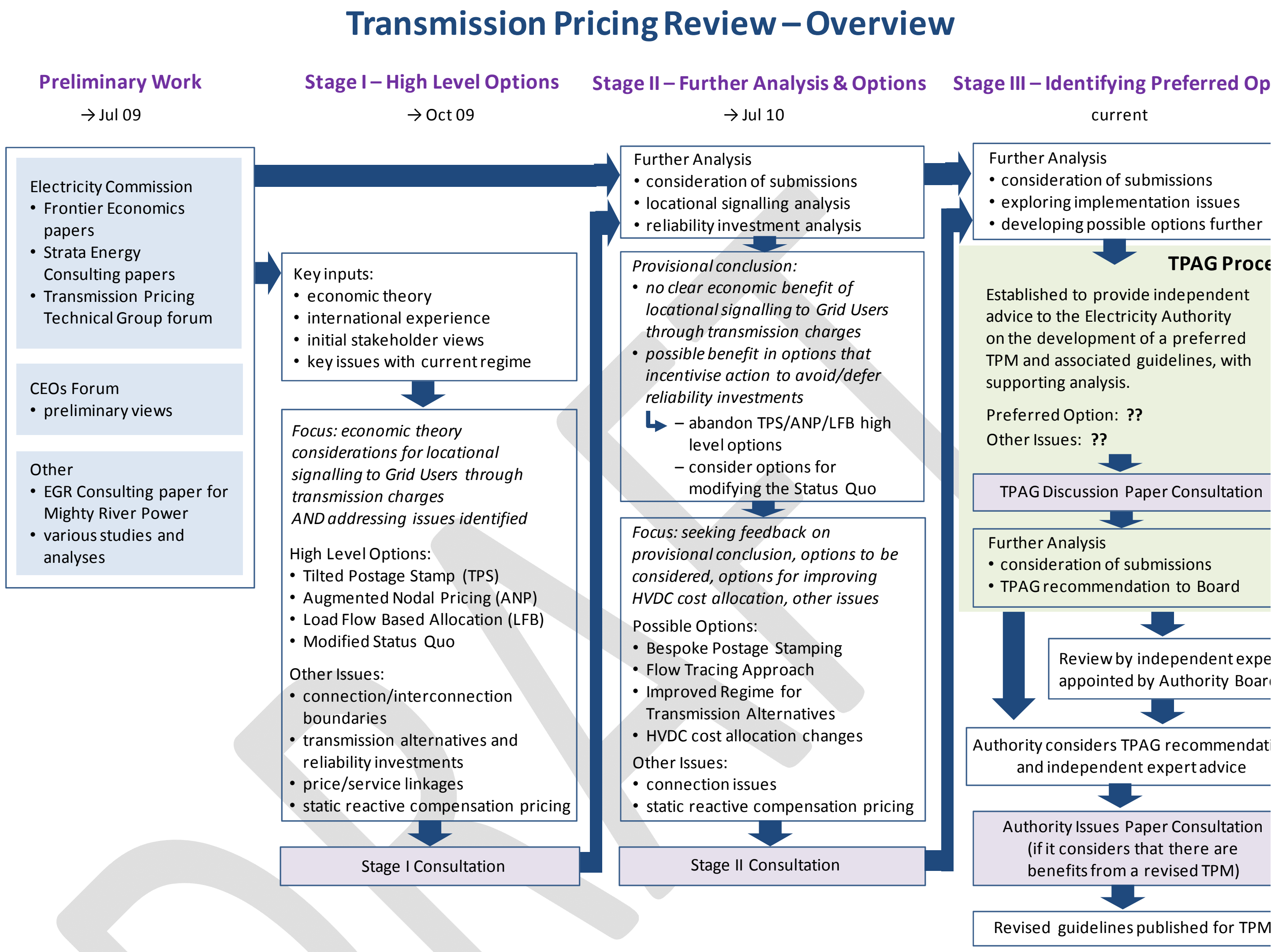
3.2.1 The Commission and a number of stakeholders undertook analysis and engaged advisers in the lead up to the Review's first formal consultation (Stage I). For the purposes of this overview, this has been grouped together as "Preliminary Work", although some of it relates to the period before the Review 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



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)[10]. 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.

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 5. 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:

[10] 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.

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.

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

Table 5 Submissions received on Stage I Consultation Paper

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

3.4.3 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.

3.4.4 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.

3.4.5 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).

3.4.6 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.

3.4.7 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.

3.4.8 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.

3.4.9 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.

3.4.10 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:

a) connection issues

b) static reactive compensation

3.4.11 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 (current)

3.5.1 Eighteen parties from across the electricity sector provided submissions on the Stage II Consultation Paper, as set out in Table 6.

Table 6 Submissions received on Stage II Consultation Paper

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

3.5.2 In very brief terms, submitters' views on key matters set out in the Stage II paper is briefly summarised in Table 7. Appendix [xx] provides a more detailed commentary on key issues raised in submissions and the TPAG's approach to considering these in its work.

Table 7 Brief summary of submissions on Stage II

Issue	Overall comment
Stage II analysis	Submitters generally concurred with the economic theory analysis that the Commission presented in the consultation paper, agreeing that the consultation paper had identified the relevant factors in its assessment of whether nodal pricing provides adequate signals for efficient generation and load investment. A minority of submitters questioned the Commission's modelling for assessing the benefits of locational signalling for economic transmission investments on the basis that the modelling was highly dependent on the input assumptions and that the use of the Generation Expansion Model (GEM) may not have been appropriate. Despite these concerns most submitters agreed with the results: that there is limited value in signalling economic transmission investments. Submitters challenged the analysis of the potential benefits of signalling reliability investments more strongly.

Issue	Overall comment
Stage II Options	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. 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.
HVDC Options	The consultation paper set out costs and benefits of the existing HVDC charge and four possible options for the allocation of HVDC costs. 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. 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.
Further Issues	Submitters commented on arrangements for independently provided connection assets. Some have suggested that, although parties should in principle be able to mutually-negotiate shared arrangements for new connection assets, in practice there is a need for intervention as a backstop. Submitters have also raised other issues in relation to connection arrangements. Of the three options presented in the consultation paper 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.

3.5.3 [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

4.1 Introduction

4.1.1 This section sets out:

a) the regulatory framework for consideration of transmission pricing options and development of guidelines; and,

b) TPAG's approach to applying this framework to assess options.

4.2 Regulatory Framework for Transmission Pricing

4.2.1 TPAG's recommendations must be consistent with the Act and the Authority's statutory objective, and have regard to any Government Policy Statement 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.

4.2.2 The Code Amendment Principles (CAPs) set out in the Consultation Charter are also relevant as they are principles that the Authority and its advisory groups must adhere to when considering Code amendments.

4.2.3 The Statutory Objective, the Code and the CAPs are considered further in the following sections. There is no relevant Government Policy Statement or Statement of Government expectations in force currently, so this aspect of the regulatory framework is not considered further.

Electricity Authority Statutory Objective

4.2.4 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[11]."

4.2.5 The Authority has finalised its interpretation of the 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.*

[11] "Consumers" is defined in the Act as "any person who is supplied, or applies to be supplied, with electricity other than for resupply". "Consumers" therefore refers to "electricity consumers".

Subpart 4 of Part 12 of the Code

4.2.6 The development of a preferred option for TPM and associated guidelines must be consistent with subpart 4 of Part 12 of the Code. Subpart 4 of Part 12 of the Code is to be amended. The amendment has been approved by the Authority Board but has not yet taken effect. Analysis is being undertaken in anticipation of the change on the basis that the Authority has already made its decision. The amendment will take effect on 1 June 2011 and will remove the transmission pricing principles and the associated interpretation provision from the Code. Under the amended subpart Transpower and the Authority's decision making regarding the TPM must be done with reference to the statutory objective. Code amendment principles

4.2.7 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.

4.2.8 The CAPS are intended to provide guidance about:

- the potential scope of the Code with regard to achieving the Authority's statutory objective; and
- how the Authority and its advisory groups will consider Code amendment matters, particularly where quantitative CBAs yield inconclusive results.

4.2.9 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.

4.2.10 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	• Must be consistent with Statutory Objective	• To be consistent with the Statutory Objective the guidelines for TPM must promote efficiency, competition and reliability.
2.	Clearly Identified Efficiency Gain or Market or Regulatory Failure	• Must be able to demonstrate an efficiency gain or a market or failure or problem with Code • To be used as a form of screening test	• Only TPM options that promise clear improvements for the long term benefit of consumers, to market efficiency, or correction of an identified market failure, should be considered. • The analysis should focus on efficiency gains (dynamic, productive, and allocative efficiency).

Principle		Key Points from Code Amendment Principles (CAP)	Applicability to TPM Guidelines
3.	Quantitative Assessment	• 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	• Quantitative CBA should be applied to assess long-term benefits associated with each of the detailed options • Competition and reliability effects are to be assessed solely in regard to their efficiency effects • Analysis of dynamic efficiency effects should be given emphasis within the CBA framework

4.2.11 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	• Favour small-scale trials	• To the extent that it can be implemented incrementally from the status quo.
2.	Preference for Competition	• Prefer options that focus on competition to achieve efficiency gains	• If CBA is inconclusive then place a preference on options that increase competition.
3.	Preference for Market solutions	• Prefer options that focus on efficient market-based structures	• 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.
4.	Preference for Opt-Out Features	• Prefer options that give participants opt-out options • However, non-rivalry and non-excludability conditions will favour "one size fits all" approach	• 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	• Focus on options that specify outputs rather than inputs	• Not applicable as the Code requires a TPM.
6.	Risk reporting	• Final tie-breaker if CBA is inconclusive	• A report assessing the risk of

Tie Breaker Principle		Key Points from Code Amendment Principles (CAP)	Applicability to TPM Guidelines
		and principles 5-8 do not discriminate • Report required to assess risks of proceeding or not proceeding with option	proceeding with the preferred option or retaining the status quo would be prepared in the event that the CBA is inconclusive and principles 5-8 do not discriminate between options.

4.3 TPAG's Approach to Assessment

4.3.1 TPAG's approach to assessment 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 for the long term benefit of consumers;

b) Clearly identified efficiency gain – any change to the TPM must demonstrate a clear efficiency gain or resolve a market failure for the long term benefit of consumers;

c) Quantitative assessment – CBA must be applied to assess the relative efficiency benefits of the TPM options for the long term benefit of consumers. There is to be a particular focus on dynamic efficiency and competition and reliability are assessed solely in regard to their economic efficiency effects. The CBA will include sensitivity analysis.

4.3.2 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 for the long term benefit of consumers, 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 Efficiency considerations

4.4.1 When considering efficiency, the key dimensions of efficiency are usefully broken down into, and assessed in terms of, dynamic, productive, and allocative efficiency. Table 10 illustrates how the limbs of the statutory objective might usefully be considered within the key dimensions of efficiency.

Table 10 Dimensions of efficiency applied to the three limbs of the statutory objective

Statutory Objective	Competition Limb	Reliability Limb	Efficiency Limb
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)

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, transactions costs of market arrangements and the administration and compliance costs and regulation 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

4.4.2 TPAG has identified important considerations that influence the efficiency of a transmission pricing regime. Table 11 summarises these 'efficiency considerations' for transmission pricing.

Table 11 Efficiency considerations

Consideration	Implication
Location price signalling	Provide additional location price signals if these promote more efficient: - coordination of investment and use of transmission, generation, and DSM; or - trade-offs between the costs and benefits of reliability.
Economic inefficiencies	Minimise economic inefficiencies arising from the TPM. Provide a level playing field for long term competition in generation and retail.
Beneficiary pays	Apply a beneficiary pays approach: - 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 benefits. Provide for transition to avoid price shocks and allow for a period of adjustment.
Simplicity & workability	Keep transition costs, transactions costs of market arrangements and the administration and compliance costs and regulation to an efficient level.

4.4.3 These efficiency considerations are discussed below.

Locational Price Signalling

4.4.4 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.

4.4.5 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 investment[12]. The TPM may be used to augment locational price signals from the nodal spot market in these situations.

4.4.6 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 demand[13] requiring transmission "reliability" investments.

4.4.7 Economic inefficiencies - Allocating fixed and sunk costs in the least distortionary manner

4.4.8 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 some unintended price signal and hence inefficiency. As a general rule the TPM aims is to minimise these economic inefficiencies.

Beneficiary pays - Role of beneficiary pays in achieving efficient outcomes

4.4.9 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.

4.4.10 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.

4.4.11 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. In a commercial environment, it is not necessary to identify all beneficiaries and free-riding is only a problem if the sum total of the free-riders ability to hold-out prevents welfare enhancing investments occurring. All that is required it that the full costs of an investment can be met from a subset of beneficiaries for which the benefits they receive exceed the costs. However there are limits to the application of this approach in a centrally planned and regulated investment environment.

4.4.12 In this environment free riders can't hold-out welfare enhancing investments, and the principle is only useful to the extent that it improves the regulated centrally planned decision making. A beneficiary pays approach may not be justified in a situation where identification of beneficiaries is costly, ad-hoc

---

12 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.

13 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

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 inefficiencies in dispatch or investment in generation or load management.

4.4.13 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.

4.4.14 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 investment (i.e. not changed arbitrarily ex-post). Ideally the cost allocation to beneficiaries should be structured so as to minimise any inefficiency in use of the new investment[14]. The costs allocated to beneficiaries should not exceed the benefits received.

Good regulatory practice

4.4.15 Good regulatory practice should seek regulation that is transparent, easily understood, justified and defendable. Where regulators' activities overlap these activities should be coordinated and consistent. Poor regulatory practice involving excessively arbitrary, subjective or ad-hoc regulation can in itself lead to significant inefficiencies if it creates regulatory uncertainty or incentives for wasteful lobbying.

4.4.16 Good regulatory practice for transmission pricing should aim to ensure that:

a) Overlaps between the Electricity Authority and the Commerce Commission decision making should be coordinated and consistent.

b) Pricing outcomes should be broadly acceptable to grid users and other stakeholders to ensure that the methodology is durable and does not trigger interventions either through the courts or through Ministerial direction.

c) A principled, consistent approach is taken 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. Ideally the approach should be applicable in a situation where significant new investments are being considered and where these investments have been just committed.

d) 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. Any proposed change should be the most effective, efficient and proportionate response to the issue concerned. 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.

[14] 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 inefficiencies.

Simplicity and workability

4.4.17 The concepts of simplicity and workability should take into account implementation and transaction costs of revisions to the TPM for industry participants, Transpower and the Electricity Authority and ensure they are kept at efficient levels.

4.5 Assessment of the options

4.5.1 The following sections of this paper contain TPAG's assessment of the transmission pricing options. TPAG has applied the efficiency consideration described in this section in its analysis. The analysis initially considers the value of location price signals (Section Error! Reference source not found.) that was considered by the Commission during stage 2 of the review. This analysis confirms the stage 2 conclusion that the benefits of these options are unlikely to outweigh the costs.

4.5.2 Section 6 contains analysis of the options for HVDC charging. This analysis applies the remaining four efficiency considerations.

4.5.3 While it is possible to approximately quantify economic inefficiences 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.

4.5.4 MAY NOT NEED THIS BIT. [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.]

4.5.5 [Section 10 considers the other options relating to deep and shallow connection and static reactive compensation pricing.

4.6 Counterfactual and sensitivity analysis

4.6.1 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.

4.6.2 The counterfactual used in the assessments in this paper includes:

a) The status quo TPM;

b) Possible future electricity sector development as defined by the range of futures outlined in the latest SOO;

c) 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.

4.6.3 Where appropriate, the assessment has considered the sensitivity of the results to different scenarios:

a) Alternative future electricity sector developments.

b) The introduction of a financial transmission right (FTR) between North and South Island nodes, with the holders of any FTR receiving the loss and constraint excess between the nodes, and the proceeds from the FTR auction allocated under different scenarios.

c) The introduction of scarcity pricing mechanisms.

5 Location-based Price Signals (this section has not yet been updated following TPAG comment)

5.1 Background

5.1.1 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.

5.1.2 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.

5.1.3 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.

5.1.4 The basis for reaching this conclusion is set out below.

5.2 The Generation Expansion Model (GEM)

5.2.1 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.

5.2.2 The GEM analysis considered the potential benefits for further locational signalling to generation and load for signalling in respect of future economic transmission investments[15].

[15] 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.

5.2.3 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.

5.2.4 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.

5.2.5 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.

5.2.6 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.

5.3 The analysis undertaken using GEM

5.3.1 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-optimise 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.

5.3.2 The analysis was based on the scenarios used for the Commission's 2010 Statement of Opportunities (SOO).

5.3.3 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.

5.3.4 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.

5.4 TPAG deliberations

5.4.1 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.

5.4.2 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". Submissions[16] on the Stage 2 Consultation Paper outlining the GEM analysis and its conclusions were largely supportive of the Commission's approach.

5.4.3 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".

5.4.4 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.

5.4.5 In response to submissions the Commission and subsequently 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.

5.4.6 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

[16] 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.

5.4.7 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.

5.4.8 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 inefficiencies and are unlikely 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].

5.4.9 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.

6 Assessing Options for HVDC Charges

6.1 Introduction

6.1.1 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 Table 12.

Table 12 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 could be based on shares of generation over the previous year, or over several years to avoid year to year variation due to hydrology.	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.

6.2 Assessing possible generation investment inefficiency with current HVDC charges

6.2.1 The primary rationale for the options in Table 12 was to find a means of allocating HVDC costs in a manner that reduced or eliminated possible inefficiencies 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 inefficiencies 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.

6.2.2 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 in the period until a new HVDC investment is required.

6.2.3 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.

6.2.4 Appendix C 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 2042;
- 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.

6.3 Expected HVDC charges and HVDC rentals

6.3.1 Transpower estimate that the real revenue requirement for the HVDC will be approximately $149m (in 2011 dollar terms) following pole 3, falling to $140m by 2020. This implies average HVDC charges of $46 to $40/kW/yr. In the past SI generators have received HVDC rentals[17] which offset the HVDC charges.

6.3.2 The Electricity Authority is about to issue a consultation paper on a locational risk management proposal. Under this proposal Financial Transmission Rights (FTRs) between Benmore (BEN) and Otahuhu (OTA) would be made available to market participation through regular auctions. These FTRs would be supported by loss and constraint rentals on the HVDC and on lines from Haywards (HAY) to OTA collected through the settlement system.

6.3.3 If this proposal is implemented SI generators paying for HVDC assets would no longer get HVDC rentals as they did in the past. However they may continue get a share of the net proceeds from the FTR auctions. In theory this should equal the expected value of the BEN to OTA[18] net rentals, however the share that SI generators are allocated may not reflect the full value of the HVDC rentals. This can occur if; rentals are retained to build up a risk management fund, the costs of running the auction are high, if participation is low and auction prices do not reflect full market value, if the allocation methodology used to apportion auction proceeds between the HVDC and the remaining HAY to OTA links is inadequate or if it is decided that that SI generators should not be allocated proceeds of the auction if they are participating in the auction for competition reasons.

---

17 HVDC rentals are collected in the settlement system and reflect the value of HVDC transfer into the receiving island net of the cost of offtakes in the sending island. These include loss and constraint rentals which vary from year to year depending on hydrology and other factors.

18 In reality only rentals associated with a FTR "grid" (including the HVDC) would be used to support FTRs. Other rentals relating to connection assets and other parts of the grid would not be used and would continue to be allocated as now.

6.3.4 Sensitivity analysis is used to deal with this uncertainty. The base case analysis assumes that SI generators get the full value of HVDC rentals and hence the net HVDC charges are equal to approximately $35/kW/yr which equals the gross HVDC charge (approximately $40/kW/yr) minus the expected value of the HVDC rentals post pole 3 (approximately $4-6/kW/yr[19]). The alternative sensitivity assumes that SI generators get no HVDC rentals and hence the HVDC charge is the full $40/kW/yr.

6.4 The opportunity cost of HVDC charge to incumbent SI Generators

6.4.1 As discussed above the average net HVDC charge facing new entrant generators in the South Island is expected to be around $35/kW/yr in real term if they continue to receive HVDC rentals. However it can be shown that, as a consequence of the cost sharing mechanism, the HVDC opportunity cost for an incumbent SI generation company is between 100% and (100% - its existing HVDC cost share), depending on the counterfactual it faces when it invests[20].

6.4.2 The potential counterfactuals and the impact on the largest incumbent's (Meridian with a 70% share of HVDC charges) opportunity cost are described in Appendix C as counterfactual 1, 2 and 3 and are summarised in Table 13.

Table 13 SI generation investment counterfactuals

Option	Description	Meridian's net 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	$35/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	$11/kW/yr (100%-70%)*35
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.	$23/kW/yr

6.4.3 It is shown in Appendix C 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.

6.4.4 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

19 See footnote 47 in Appendix F for details.

20 This issue was raised in submissions by RTANZ, Norske Skog, Meridian and TrustPower. RTANZ claim that counterfactual 1 applies and everyone investing in the SI faces the same opportunity cost. Norske Skog agrees this is an issue, but believes it can be resolved by only charging HVDC costs to existing generation. Meridian and TrustPower focus on counterfactuals 2 and 3 and sees the current allocation as a barrier to new investors in grid connected SI generation.

directly with relatively low cost NI options in a national market. However under counterfactual 3 Meridian has a substantial \$24/kW (\$35 less \$11) advantage over its SI competitors. If this was the case, Meridian is likely to increase its dominance in the SI.

6.4.5 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[21].

6.5 Results of possible generation investment inefficiency analysis

6.5.1 Table 14 summarises the results of the simplified analysis. The analysis of the economic costs is dependent on a number of assumptions including the value of HVDC rentals received[22], new investment costs, fuel costs, exchange rates and other factors. For this reason sensitivity to these factors was tested and is reported in Appendix C.

6.5.2 Table 14 suggests that the generation investment inefficiency associated with the HVDC charge could be between \$14m and \$51m (average \$31m) if SI generators continue to receive HVDC rentals, or between \$19m and \$64m (average \$38m) if they don't. 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 14 Generation Investment Inefficiency of HVDC charge (HAMI allocation)

HVDC Rentals	Net HVDC Opportunity Cost	Economic cost (NPV)	
		Base Case	Low gas price
SI generators continue to get HVDC rentals	\$35/kW/yr	\$14-45m (average \$28m)	\$20-51m (average \$34m)
SI generators don't get HVDC rentals	\$40/kW/yr	\$19-54m (average \$33m)	\$27-64m (average \$42m)

6.6 Relevance of beneficiary pays considerations

6.6.1 As discussed in section 4, 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 possible[23]. However, any decision to apply a beneficiary-pays approach to some portion of the grid assets requires

[21] This assumes that any reduction in generation investment inefficiency under counterfactuals 2 and 3 is offset by the costs of Meridian increasing its dominance in the SI. This would provide a lower estimate of the total economic inefficiency if the cost of Meridian increasing its dominance is greater than \$5-10m NPV.

[22] There is some doubt that SI generators will continue to receive the HVDC rentals if the location hedging proposal goes ahead, hence sensitivity without HVDC rentals is included.

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

considerations of whether overall the benefits outweigh the costs and whether the application of the approach represents good regulatory practice.

6.6.2 It is recognised that it is not necessary to identify every beneficiary of an investment and, that under a central planning approach to HVDC investments, the existence of free-riders will not prevent welfare enhancing investments occurring. It is sufficient to allocate the costs of an investment to a subset of beneficiaries provided the allocated costs do not exceed the benefits received..

6.6.3 The benefits of applying the approach may be 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 inefficiencies. If the beneficiaries are too broadly spread or uncertain then the value obtained from a beneficiary pays approach may not be justified by the costs.

6.6.4 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.

6.6.5 Beneficiaries of the HVDC are widely spread, and it would be difficult to objectively and robustly quantify the benefits to the different groups as this depends on debateable forecasts of future scenario probabilities, resource availability and costs, carbon prices, fuel prices etc.

6.6.6 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 (and not exceed) the value they would be prepared to pay prior to the investment[24] (ex-ante) and not arbitrarily changed afterwards (ex-post).

6.6.7 Application of the beneficiary pays approach to HVDC assets would be inconsistent in that it is not materially different to other interconnection asset investments (e.g. NIGUP) where identification of specific beneficiaries is clearer and more robust.

6.6.8 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 centrally estimate and allocate specific shares of benefits to the different groups of beneficiaries is likely to be outweighed by the costs[25]. The costs and benefits of using a market based approach to identify beneficiaries is explored further in the discussion below on capacity rights.

6.7 HVDC Capacity Rights

6.7.1 It has been suggested that HVDC capacity rights might be a market based approach to identify beneficiaries of the HVDC. There are two potential forms of HVDC capacity rights that might be considered; a merchant link model whereby parties funding a new investment in the HVDC receive

---

[24] If a subgroup of beneficiaries is to pay for new investments then you might expect them to have some decision rights, however this may create significant problems for the centrally planned grid investment process if the private benefit to that subgroup does not equal the national benefit.

[25] 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.

dispatch rights and rentals on the capacity they pay for and the NZIER proposal[26] which involves an allocation or auctioning of physical rights to transfer energy across the link.

6.7.2 The key features are summarised in the table below.

Table 15: Capacity Rights Options

	NZIER Proposal	Merchant Link Proposal
Overseas model	[None]?	Australian market interconnector regime[27].
Concept	Generators wishing to "use" the HVDC would need to hold a HVDC Capacity Right to be dispatched.	Users paying for link Capacity Rights would receive rentals and would be able to "offer" link capacity into the market in competition with generators in the sending and receiving regions.
Initial Allocation	Rights to use the existing HVDC could be auctioned or allocated according to some measure of historical "use" or "benefit". Rights to new capacity could be given to parties that pay.	Dispatch rights to the existing HVDC could also be auctioned or allocated, and rights to new capacity could be given to parties who pay. There could be separate dispatch rights for capacity in each direction.
Secondary Trading	Requires half hour secondary trading up to gate closure and a separate spot auction of rights alongside SDP.	Additional secondary trading may occur if there is a demand, but is not required.
Market clearing and Settlement	Requires a 2 solve process[28] to identify "users"[29] of the HVDC, and integration of separate spot trading regime. Energy and reserve prices will be affected.	SPD needs to be modified to include link offers, but otherwise it is co-optimised and settled as now. Energy and reserve prices will be affected.
Issues for Transpower	Transpower may face risks if it issues "firm" rights and may earn excess or shortfall returns.	Same as NZIER
New Investment	There can be issues if there is excess capacity arising from taking advantage of economies of scale. This may require Transpower, or the party paying, pricing up excess capacity for a period.	Same as NZIER

26 See "A capacity Rights Regime for the HVDC Link", NZIER Report to Rio Tinto Alcan New Zealand Ltd, 22 March 2010.

27 The only remaining market interconnector in the Australian market is Basslink, MurryLink and Directlink were built as merchant links, but have now been converted to regulated status.

28 There are detailed implementation issues and modifications to deal with spurious results and to handle losses and constraints as described in "NZIER Capacity Rights Proposal – Implementation Issues", Electricity Authority 30 November 2010.

29 Although it may be possible to identify "users" of the HVDC using this 2 solve approach, it would be much more difficult to identify all the possible "beneficiaries" and it would be very costly to require that all these parties actively trade link rights to match

	NZIER Proposal	Merchant Link Proposal
Location Hedging	Would provide BEN-HAY hedging, but not HAY-OTA.	Same as NZIER
System Security	May require mandatory offering of HVDC rights up to physical capacity?	Same as NZIER
Market Power	Strategic offering of energy, reserve and HVDC capacity can cause inefficient dispatch if there is inadequate competition.	Same as NZIER
Other		The merchant link approach could potentially be applied to other AC interconnections[30].

6.7.3 The merchant link option would be much simpler to implement and less costly to operate and administer (it avoids 2 or 3 solve process and the need for continuous secondary trading). This approach does not require "users" or "beneficiaries" of the HVDC to be identified each trading period.

6.7.4 The NZIER approach is more costly to implement and operate but it does identify "users" of the HVDC. This is not necessary if Capacity Rights are auctioned or provided as part of a new investment agreement, however it may be necessary if Capacity Rights are allocated according to "use". Both of these options have similar issues for Transpower, hedging, system security and market power.

6.7.5 Proponents of the Capacity Rights options 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.

6.7.6 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 inefficiencies and the potential for exercise of short-term market power; and

[30] Although it is not possible to dispatch AC "links" directly it may be possible to incorporate offers for the use of AC interconnectors or "flowgates" into the market clearing engine and to derive prices and generation dispatch that reflects these.

- There would likely be material implementation and transaction costs associated with these capacity rights arrangements, particularly the NZIER option.

6.7.7 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 is 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).

6.8 Possible benefit from deferring or avoiding new HVDC investment

6.8.1 It is possible that the generation investment inefficiencies discussed above may be offset by the benefits of deferring or avoiding new HVDC investment in the future.

6.8.2 It is noted that the estimates of generation investment inefficiency discussed above only relate to changes in the timing of generation options that can be accommodated within the committed capacity of the HVDC, and only for the next 30 years.

6.8.3 Another new investment in the HVDC is not expected for 30 years, but circumstances could change. If and when a new investment is required it will need to be justified on the basis of the grid investment test. This will need to show that the additional transmission costs are justified by the benefits of lower system costs to New Zealand as a whole.

6.8.4 Consistent application of the beneficial pays principle would suggest that if a specific beneficiary can be clearly, cheaply and objectively identified prior to the new investment being approved then it should be allocated costs up to the level of benefits it receives.

6.8.5 By the time a new HVDC investment is required for economic reasons it is possible that the design and other issues associated with one of the Capacity Rights approaches may have been resolved, and a commercial market-driven approach could be applied.

6.8.6 These mechanisms, rather than the current HVDC cost allocation, will largely determine the efficient timing and size of future HVDC investments if and when they may be required. For this reason there is likely to little benefit from the discouraging SI investment in the intervening period.

6.9 Change to MWh cost allocation to all SI generators

6.9.1 The alternative “MWh charge” option described in Table 12 has been suggested as a means of reducing the possible economic inefficiencies 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.

6.9.2 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 year to year fluctuations due to hydrology and to avoid short-term incentives to withhold generation.

6.9.3 The investment inefficiency analysis has been repeated with an \$8/MWh charge. The results are summarised in Table 16 which confirms that the economic inefficiency 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 Generation Investment Inefficiency of HAMI and MWh HVDC charges

HVDC Rental allocation	HVDC cost allocation and net Opportunity Cost	Economic Cost	
		Base Case	Low gas price
SI generators continue to get HVDC rentals	$35/kW/yr HAMI	$14-45m (average $28m)	$20-51m (average $34m)
	$7/MWh	$9-28m (average $18m)	$13-33m (average $22m)
SI generators don't get HVDC rentals	$40/kW HAMI	$19-54m (average $33m)	$27-64m (average $42m)
	$8/MWh	$10-33m (average $22m)	$15-36m (average $28m)

6.9.4 The analysis suggests that the potential generation investment inefficiency would fall by around $10-12m on average, if the existing HVDC charge remained on South Island generators but was allocated proportionately to generation in MWh rather than HAMI.

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

- Reducing incentives to withhold offers of short-term generating capacity in the SI[31];
- Reducing incentives to mothball or retire existing peaking capacity in the SI[32];
- 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).

6.9.6 However, a generation investment inefficiency of between $9m and $33m (average $20m) would remain if SI generators receive HVDC rentals and between $10-36m (average$26m) if they don't.

6.9.7 A per-MWh allocation can result in some operational dispatch inefficiencies as well. 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 model[33] 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.

6.10 Alternative MWh cost allocation methodologies

6.10.1 Todd and Meridian suggested an alternative MWh allocation whereby the HVDC costs could be allocated to generators and loads in each island based on MWh flows in each direction. Northward flows could be shared equally between SI generators and NI loads and Southward flows could be recovered from all loads. Other sharing formula could be used. It is noted that flows may not necessarily reflect value, and that some account of the price differences might be used in a sharing formula.

31 Some generators are withholding over 100MW of peaking capacity in the SI as a result of the HAMI allocation. This is available for grid emergencies as Transpower has agreed not to adjust the HAMI in this case, but it is not made available at other times. In the worst case this could lead to the construction of an extra 100MW of NI peaking capacity at the cost of $100m, but it is more likely that withheld capacity would be returned to the market once the value of SI peaking increases.

32 The Electricity Commission estimated that the cost this could be in the range $0-25m NPV, see section 4 of Appendix 4 to the Stage 2 review.

33 See section 5 of Appendix 4 to the Electricity Commission's Transmission Pricing Review: Stage 2 Options, July 2010.

6.10.2 These alternative MWh allocation methodologies would have a similar effect to the full MWh allocation to SI generators. They could lead to dispatch inefficiencies, but would further reduce the generation investment inefficiencies to the extent that the expected MWh charge to SI generators was lowered.

6.11 Postage Stamping the HVDC charge

6.11.1 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.

6.11.2 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, customers would receive HVDC rentals and customers would likely see an average increase in delivered energy prices of approximately $3/MWh[34]. 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 prices[35].

6.11.3 This price increase would be an immediate and certain, but should be offset by a possible fall in wholesale prices in the medium term, as market prices adapt to a $4-11/MWh drop in SI LRMC. The possible net effect over time is illustrated in Figure 3.

6.11.4 If prices were to rise by $3/MWh without any countervailing drop in wholesale prices there could be a deadweight loss[36] associated with the price increase estimated as $0.3m/yr[37] or $3m 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 Figure 3 the deadweight loss would be approximately $1m net present value.

---

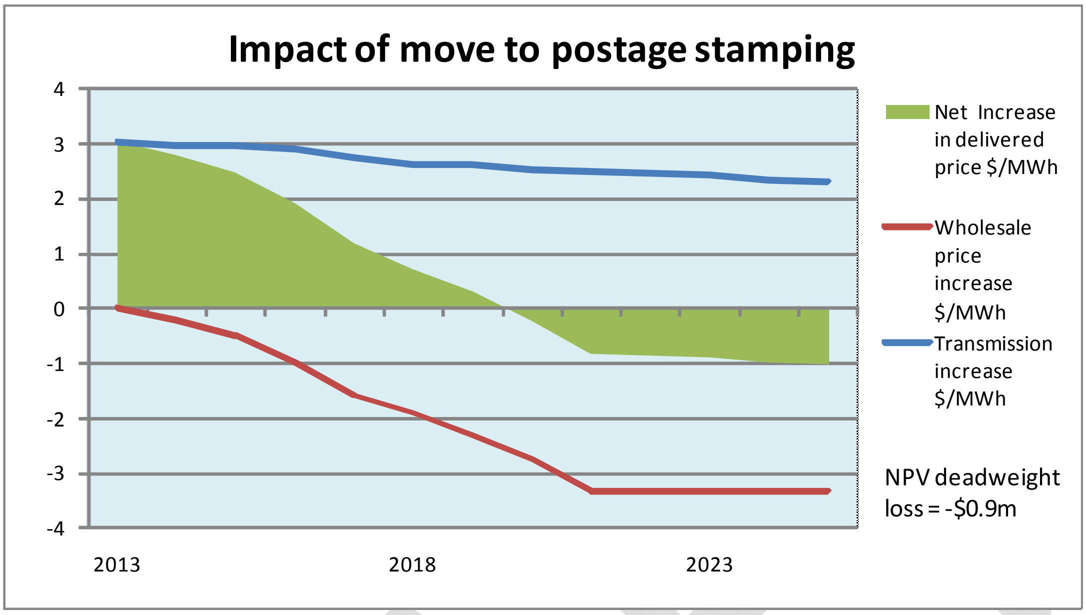
34 This is estimated on the basis of $147m real HVDC revenue requirement in 2013/14 minus $14m expected HVDC rentals over total NZ off take demand of approximately 42,000GWh.

35 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/MWh increase, half coming from higher wholesale prices and half from higher interconnection prices.

36 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 inefficiency.

37 $3/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*200/2 = $300,000/yr.

Figure 3 Possible impact of a move to postage stamping HVDC charges



6.11.5 This potential deadweight loss might be offset if there are efficiency gains from higher RCDP charges deferring transmission reliability investments[38].

6.11.6 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.

6.11.7 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.

[38] 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.

6.11.8 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.

6.11.9 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.

6.11.10 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.

6.11.11 Moving to a MWh allocation of HVDC charges leaves approximately $9-33m ($20m average) NPV generation investment inefficiencies, but would avoid significant value transfers. It is debateable whether the benefit of removing this residual inefficiency 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 inefficiencies and minimises the value impacts.

6.12 Possible transition to Postage Stamping the HVDC charge

6.12.1 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. This approach could enable the removal of the residual inefficiencies described above without creating significant value transfers.

6.12.2 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:

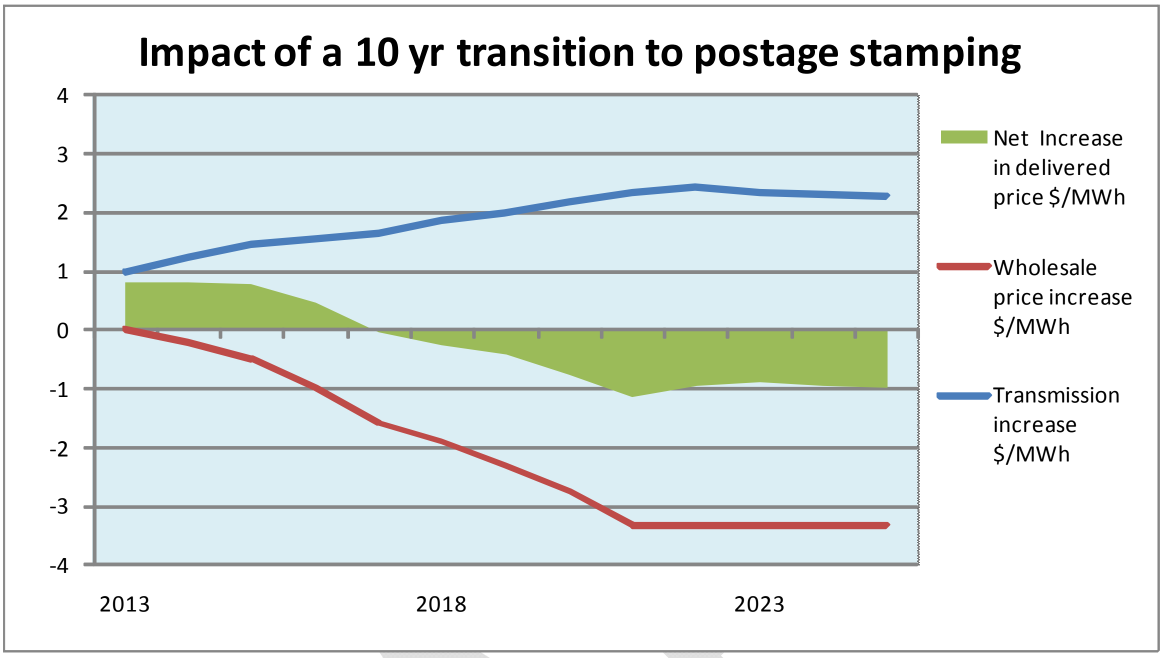
- The current SI generators continue to meet the HVDC charges associated with the old HVDC assets (in the same proportions as for the status quo) with the charges phased out over a transitional period;
- New SI generation projects are not required to pay HVDC charges;
- The residual HVDC costs (the cost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

6.12.3 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 charges[39].

6.12.4 The transition could be designed to minimise the price shock. For example it would be possible to allocate approximately 64% of the total HVDC costs in 2013 relating to the old HVDC link to existing SI generators on the basis of historical shares, and then phase this out over time. The impact of a 10 year transition is illustrated in Figure 4. This reduces the net impact on customers to less than $1/MWh in the short run, which would largely eliminate any material deadweight loss associated with the change in HVDC charges.

[39] 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.

Figure 4 Possible impact of a 10 year transition to postage stamping HVDC charges



6.13 Summary of HVDC Options

6.13.1 Table 17 summarises the advantages and disadvantages of the HVDC options considered in this discussion paper. Note that the values reflect are based on SI generators continuing to receive the share of HVDC rentals that they pay for. The values would be greater if they didn't.

Table 17 Advantages and disadvantages of HVDC options

Option	Pros	Value	Cons	Value
Status Quo	• Consistent with charging practice over last [11] years • May defer or prevent the need for future HVDC or AC transmission capacity.	low	• 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	Low $0-25m $14-51m ?

Option	Pros	Value	Cons	Value
Capacity Rights	• 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.	? ? ?	• 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 risks or shortfall for Transpower	? high ?
MWh Charge	• Reduces short-term operational inefficiency in SI • Reduces the deterrent for investment in SI peaking capacity • Reduces the inefficiency of incentives for new generation between NI/SI	Low $0-25m $12m	• Some remaining NI/SI new generation inefficiency and still provides an artificial competitive advantage for Meridian • Minor remaining dispatch inefficiency which could increase if there is SI thermal • Inconsistent application of beneficiary pays principle for pole 3	$9-33m $1-5m ?
Postage Stamp	• Eliminates short-term operation inefficiency in SI • Eliminates the deterrent for investment in SI peaking capacity • Eliminates the inefficiency of incentives for new generation between NI/SI and btw SI gens	Low $0-25m $14-51m	• Small deadweight loss from price shock • Value shift in transition is inconsistent with good regulatory practice	$0-3m ?
Incentive free allocation to existing SI	• Would eliminate operational and generation investment inefficiencies, but may not be practical	Same as postage stamp if feasible	• It is difficult to devise an acceptable methodology other than as part of a transition, this option had no supporters	
Postage Stamp Transition	• Eliminates short-term operational inefficiency in SI • Eliminates the deterrent for investment in SI peaking capacity • Eliminates the inefficiency of incentives for new generation between NI/SI and btw SI gens	Low $0-25m $14-51m	• Minimises value shift and deadweight loss by avoiding price shock. • Costs of design • Potential for dispute	Low Low Low

7 Assessing other Options

7.1 Connection

7.1.1 To be drafted

7.1.2 Defer consideration

7.2 Static Reactive Compensation

7.2.1 New group

7.2.2 Defer consideration

8 Preferred Option for TPM

8.1 Description of Preferred TPM

8.1.1 To be drafted

8.2 Cost-Benefit Analysis

8.2.1 To be drafted

8.3 Applying the Evaluation Criteria

8.3.1 To be drafted

9 Conclusion

9.1 Outcomes from Assessment

9.1.1 To be drafted

9.2 Recommended TPM Guidelines

9.2.1 To be drafted

9.3 Issues for Submission

9.3.1 To be drafted

Appendix A List of questions

A.1.1 To be drafted

Appendix B Submissions Summary

B.1.1 To be drafted

B.1.2 To be drafted

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

Methodology for assessing possible investment inefficiency

C.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.

C.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)[40].

C.3 It should be noted that this Appendix only considers the possible generation investment inefficiency arising from HVDC cost recovery. It does not consider, or attempt to quantify, the possible benefit of deferring or preventing investment in a new or expanded HVDC link, or the possible benefit of deferring AC transmission upgrades necessary to support an expanded HVDC link. The analysis only considers generation options that can be accommodated within the committed capacity of the HVDC.

C.4 This appendix describes a simplified analysis[41] 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 options[42];
- 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 factors[43];
- 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;

40 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.

41 This simplified analysis is able to address some of the concerns raised by submitters with respect to the GEM model and analysis. While approximate, the analysis is very transparent, and enables a full set of sensitivities to be explored.

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

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

- 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 price[44].

Constructing the merit order

C.5 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.

C.6 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 though the application of HVDC charges on SI generation projects.

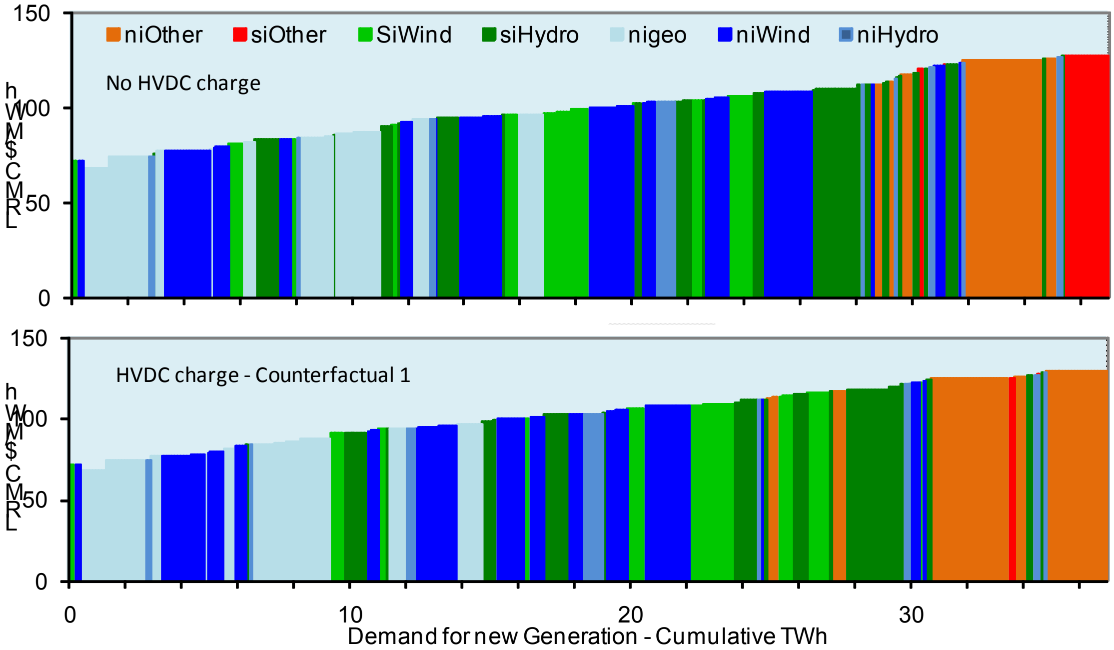
C.7 Figure 5 illustrates the two different merit orders used in this analysis, highlighting that a range of geothermal and wind projects appear to provide the cheapest development options[45]. Note that 10 TWh represents approximately 25% of today's annual electricity demand.

C.8 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.

[44] 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.

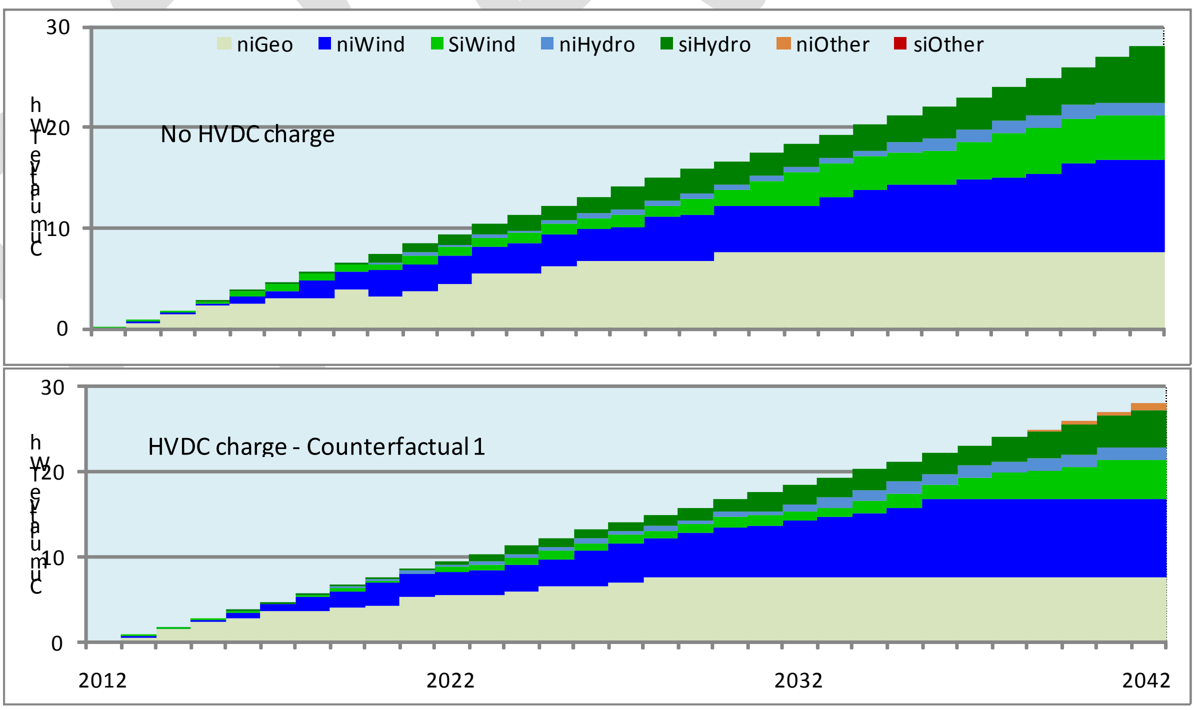
[45] The long run marginal costs have been estimated using an assessed weighted-average-cost-of-capital (WACC) of 7% real post-tax. This reflects a typical commercial rate of return required by generators.

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



C.9 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.

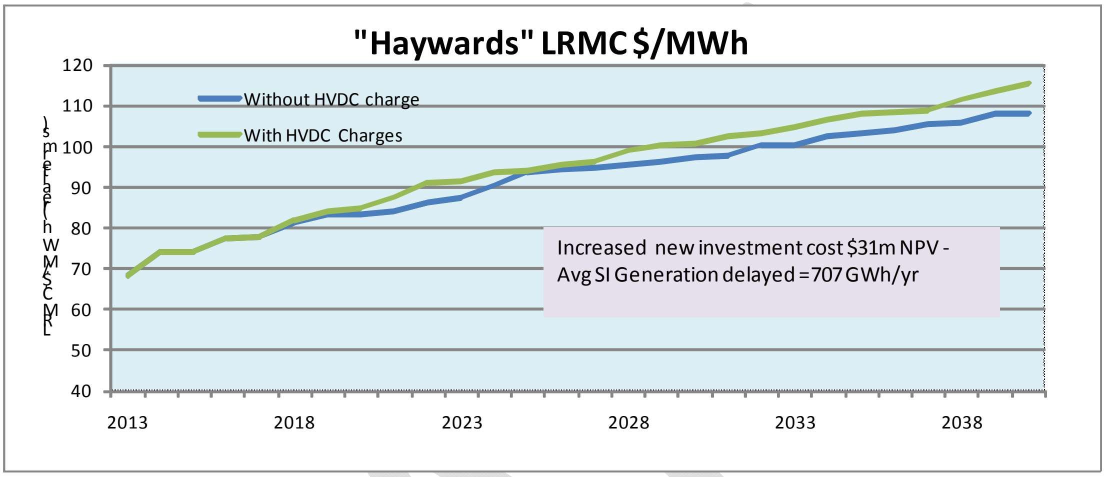
Figure 6 Illustrative impact on timing of investment



C.10 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.

C.11 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

C.12 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 rate[46].

C.13 The analysis assumes that the average net HVDC charge under the existing price structure is $35/kW/yr in real 2011 dollar terms[47].

C.14 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 know to within ±30%. To account for these 10 separate cases were evaluated with individual project costs being randomly varied by ± 20% around a generic capital cost for each general class of investments (geothermal, wind, hydro thermal etc).

C.15 For this reason sensitivity to these factors was tested and reported in Table 18.

---

46 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.

47 In reality the gross HVDC charge (in real 2011 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. Currently parties paying HVDC charges receive HVDC rentals. A study by Energy Link prepared for the Electricity Authority in March 2011 estimates these to be worth around $4-6/KW/yr following the commissioning of pole 3. The net HVDC charge is thus around $35/kW/yr over the 15 years following pole 3. The possibility that these rentals may be used to support the locational hedging proposal is treated as sensitivity.

Table 18 Generation Investment inefficiency with a HAMI charge- Sensitivity Analysis

HVDC Charge $35/kW	Economic Cost $m PV	
Sensitivity	**Base Case**	**Low Gas cost Scenario**
Current Exchange rates	$18m	$25m
Long run Exchange Rates	$16m	$25m
Random Capex 1	$34m	$37m
Random Capex 2	$37m	$41m
Random Capex 3	$27m	$30m
Random Capex 4	$28m	$38m
Random Capex 5	$27m	$43m
Random Capex 6	$45m	$51m
Random Capex 7	$17m	$25m
Random Capex 8	$14m	$20m
Random Capex 9	$42m	$47m
Random Capex 10	$30m	$29m
Average	$28m	$34m

C.16 The sensitivity analysis undertaken for a $35/kW/yr HAMI charge suggests an economic cost in a band of $14m to $51m (average $31m).

Change from HAMI cost allocation

C.17 The alternative MWh charge option described in Table 13 has been suggested as a means of reducing any possible economic inefficiency from charging HVDC costs to SI generators. Recovering the same revenue over all SI generation could be achieved with a $7/MWh charge instead of a $35/kW HAMI charge.

C.18 The investment inefficiency analysis has therefore been repeated with a $7/MWh charge. The results are summarised in Table 19 which confirms that the economic inefficiency is likely to be lower with HVDC costs allocated to SI generators on the basis of a per MWh charge rather than HAMI[48].

48 Note that there are additional economic inefficiencies 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).

Table 19 Generation Investment Inefficiency with a $7/MWh HVDC charge

HVDC Charge $7/MWh	Economic Cost $m PV		Difference from HAMI	
Sensitivity	**Base Case**	**Low Gas cost**	**Base Case**	**Low Gas cost**
Current Exchange rates	$12m	$13m	-$6m	-$12m
Long run Exchange Rates	$10m	$18m	-$6m	-$7m
Random Capex 1	$19m	$20m	-$15m	-$16m
Random Capex 2	$28m	$33m	-$9m	-$8m
Random Capex 3	$22m	$24m	-$5m	-$6m
Random Capex 4	$22m	$30m	-$6m	-$8m
Random Capex 5	$16m	$20m	-$11m	-$23m
Random Capex 6	$20m	$22m	-$25m	-$29m
Random Capex 7	$14m	$22m	-$3m	-$3m
Random Capex 8	$9m	$14m	-$5m	-$6m
Random Capex 9	$24m	$26m	-$18m	-$21m
Random Capex 10	$23m	$26m	-$8m	-$4m
Average	$18m	$22m	-$10m	-$12m

C.19 The sensitivity analysis for a $7/MWh HVDC charge suggests an economic cost in a band of $9m to $33m (average $20m).

C.20 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 $9-$11/MWh disadvantage for SI projects, whereas this is reduced to $7/MWh under a MWh allocation.

Opportunity cost of HVDC charges to Incumbent SI Generators

C.21 The analysis above is based on a $35/kW/yr or a $7/MWh HVDC charge facing new entrant generators in the South Island. However this may not be equal to the opportunity cost for incumbent generators.

C.22 The opportunity cost of the HVDC charges for an incumbent SI generator depends on both its share of the HVDC chares 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 ($35/kW/yr), but all the incumbents will benefit from a reduction in their share of the costs. It can be shown[49] that the HVDC opportunity cost for an incumbent investing in the South Island is between 100% of the full HVDC cost ($35/kW/yr) and (1-share[50]) times the full HVDC cost depending on the investment counterfactual.

C.23 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 net 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	$35/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	$11/kW/yr =(100%-70%)*35
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.	$23/kW/yr

C.24 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 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 1[51].

---

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

[50] 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.

[51] 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.

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	$35/kW/yr	**$28m** ($14-$45m)	**$34m** ($20-$51m)
2. Intermediate	$23/kW/yr	**$23m** ($12-$36m)	**$28m** ($18-$39m)
3. Displaces NI generation	$11/kW/yr	**$19m** ($11-$32m)	**$23m** ($15-$36m)

C.25 However, note that under counterfactual 3 Meridian has a $26/kW ($35 less $11) 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.

C.26 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.

C.27 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. This assumes that the cost of Meridian increasing its dominance in the SI offsets any reduction in the generation investment inefficiency with counterfactuals 2 and 3.

HVDC rental allocation sensitivity

C.28 The analysis above is based on the assumption that SI generators paying HVDC charges continue to receive HVDC rentals worth between $4-6/kW/yr following the commissioning of pole 3.

C.29 It is possible that HVDC rentals may be used to support Financial Transmission Rights auctioned under the locational risk management proposal. In this case it is possible that SI generators may not receive the full value of these HVDC rentals.

C.30 Table 22 shows the economic cost of HVDC charges (under counterfactual 1) in the event that SI generators receive no rentals, and hence face the full gross HVDC charges of $40/kW/yr.

Table 22 Generation Investment Inefficiency from HVDC charges without rentals.

HVDC cost allocation	HVDC opportunity cost	Average Economic cost (NPV)	
		Base Case	Low gas price
HAMI Allocation	$40/kW/yr	**$33m** ($19-$54m)	**$42m** ($27-$64m)
MWh Allocation	$8/MWh	**$22m** ($10-$33m)	**$28m** ($15-$36m)

C.31 In this case the generation investment inefficiency is increased by around $6 to $8m to approximately $19-$64m (average $38m) for a HAMI allocation and $10-36m (average $26m) under a MWh allocation.

References

[insert text]