28 August 2009

New Zealand Transmission Pricing Project

A Report for the New Zealand Electricity Industry Steering Group

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[*] This report has also benefited greatly from the assistance of Neil Walbran. Notwithstanding, responsibility for any errors and omissions remains with the authors.

Foreword

This report was originally prepared for the New Zealand Electricity Industry Steering Group in late August 2009 and first discussed by the Steering Group on 2 September 2009. Important to the context for the report at that time was a degree of uncertainty as to how the long term, forward-looking power flows likely to be experienced on New Zealand's electricity transmission network could best be characterised. The ensuing 'grid characterisation' is important for determining the nature and extent of Transpower's anticipated capital investment program and, particularly, its sensitivity to different potential generator location decisions. Each of these factors is in turn critical for determining the nature and extent of any enhanced generator locational signals that it may be appropriate to put in place in any reform of the existing transmission pricing methodology.

Since the time our report was first prepared, Transpower has undertaken a detailed analysis of these empirical questions and, essentially, drawn the conclusion that the transmission grid should be characterised as facilitating a long term northward flow of power, although with some regional variations around that theme. It follows that our report and the transmission pricing options that it identifies and evaluates should now be read in conjunction with the results of Transpower's analysis, including the conditionalities and qualifications that surround those empirical conclusions.

The original 28 August 2009 version included a preliminary or 'strawman' application of the 'tilted postage stamp' methodology discussed in section 5.1. This was based on an indicative future investment program as then provided by Transpower (see Appendix A), along with a number of assumptions required to derive preliminary estimates of the region-specific, long run marginal cost of transmission.

In its subsequent work, Transpower has undertaken a much more detailed assessment of its forward-looking capital investment programme and its sensitivity different generator location decisions that might arise in response to a wide range of potential 'tilted postage stamp' transmission pricing outcomes. This work supersedes the preliminary analysis included in the original version and so the relevant section has been removed from this version prior to it being made available to interested parties outside the New Zealand Electricity Industry Steering Group process. For similar reasons, we have also removed a section in the original version that sought to assess the extent to which the existing HVDC charge reflects the long run marginal cost of south to north transmission.

This public version of the report also incorporates at Appendix D a paper prepared for the Industry Transmission Pricing Project Working Group in July 2009 entitled 'Market Based Transmission Investment', since the subject of that paper remains relevant to the options being considered by the Steering Group.

Finally, a number of minor changes have been made throughout the report so as to reflect the various changes identified above. However, none of these amendments has altered either the substance or form of the analysis as originally presented.

NERA Economic Consulting, 9 December 2009

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Executive Summary

The purpose of this review is to explore ways in which to improve the efficiency of electricity transmission pricing arrangements in the New Zealand Electricity Market (NZEM). The touchstone for any proposed options for reform should be the potential for *material improvement* upon the existing arrangements, ie, the enhancement of economic efficiency through altering the *commercial incentives* facing market participants and ultimately their decisions/conduct, so as to produce more desirable outcomes.

The principal mechanism for achieving an efficient degree of coordination between transmission and generation in a vertically-separated electricity industry such as the NZEM is through *price* signals. In a disaggregated industry in which generators and consumers react to market signals, the level and structure of transmission charges has a potentially significant effect on network use and, to a lesser extent, transmission investment. Transmission charges may also affect the *locational choices* of new generation and energy intensive users, as well as potentially influencing the bidding conduct of generators.

Setting such charges at the right level is critical for ensuring the efficient use of and investment in the transmission network. It is also one of the most challenging problems facing regulators. In particular, we understand that industry and major consumer stakeholders would like to see a transmission pricing methodology that:

- sends efficient locational signals (assuming these signals are not adequately provided elsewhere);
- sends efficient signals to encourage, among other things, efficient demand-side response;
- sends efficient signals as to the timing and nature (as well as location, identified above) of new generation development; and
- endures in line with the time frames for investment decisions so as to provide certainty as to the nature and extent of those price signals to all stakeholders.

In order to identify potential options for change to the arrangements that are most likely to meet these objectives, it is necessary first to understand the arrangements that are *currently* in place and, critically, to understand the incentives (both positive and negative, or productive and counter-productive) that are created by them. Accordingly, at the highest level our approach comprises two steps:

Step One: Consider the extent to which the *existing* transmission pricing arrangements are consistent with the fundamental objective and support the achievement of efficient outcomes. The Steering Group has a very important role to play in the process of identifying and understanding the various incentives that arise under the current arrangements, and this itself is an important objective of this paper.

Step Two: For those aspects of the existing arrangements that are not demonstrably consistent with the fundamental objective, consider whether any potential reforms may give rise to more efficient outcomes, thereby representing a material improvement. In this process, the Steering Committee has a similarly critical role in identifying the incentives likely to arise under the various reform options set out in this paper.

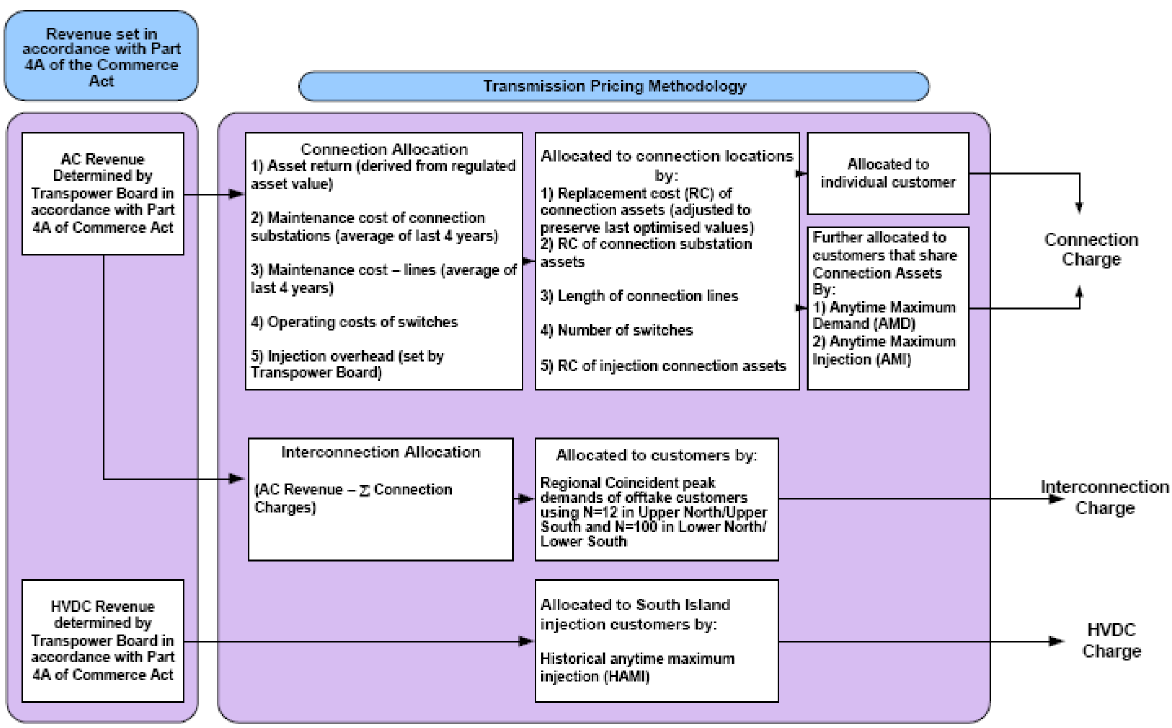
Summary of Existing Arrangements

The way in which Transpower recovers the full economic costs associated with providing electricity transmission services, including capital, maintenance, operating and overhead costs, is contained within its Transmission Pricing Methodology (TPM). The costs associated with *existing* transmission assets are recovered as follows:

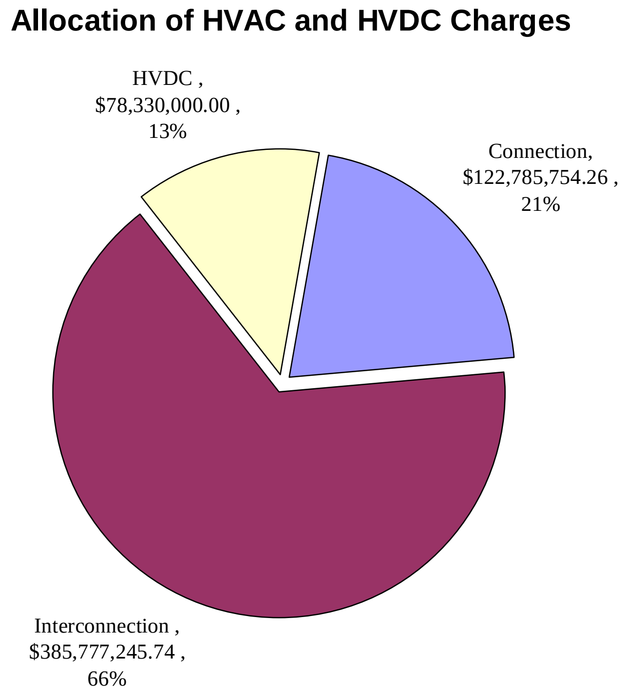
- the costs associated with existing connection assets are recovered from both off-take and injection customers on the basis of their anytime maximum demand (AMD) and anytime maximum injection (AMI), respectively;
- the costs associated with existing interconnection assets are recovered solely from off-take customers, with the allocation based on their contribution to the average regional coincident peak demand (RCPD) in four separate pricing regions; and
- the costs associated with existing high voltage direct current (HVDC) assets are recovered from South Island injection customers on the basis of their historic anytime maximum injection (HAMI).

The figure below, which is reproduced from the TPM, provides a summary of Transpower's charges for existing network assets.

Summary of Transpower's Charges for Existing Network Assets



The following chart approximates the allocation of high voltage alternating current (HVAC) and HVDC charges for existing network assets. The data for connection and interconnection charges relates to the 1 April 2008 to 31 March 2009 period, whereas the HVDC charges are for the 2009/10 period (before congestion rentals).



There are two separate (but related) mechanisms by which investments in *new* transmission assets are recovered by Transpower, specifically:

- the costs associated with investments that have passed the grid investment test (GIT) are recovered by Transpower ***under the TPM***, eg, new investments in interconnection assets that have passed the GIT are recovered from off-take customers based on their RCPDs as applicable; and
- the capital component of a customer-funded investment in new connection assets is recovered through a new investment contract (NIC), with non-capital costs continuing to be funded under the TPM.[1]

Customers also have the option of constructing new connection assets themselves, or entering into contractual arrangements with parties other than Transpower, eg, distribution companies. In these instances, connection lines cease to be 'open access' and connection charges are limited to a return on dedicated customer assets at grid exit/injection points.

Further important features of the TPM include the arrangements by which Transpower can procure transmission alternatives (such as energy efficiency initiatives and local generation) and its prudent discount policy, which is intended to ensure that the TPM does not provide incentives for the uneconomic bypass of existing grid assets. Finally, the regulatory arrangements for the connection of *embedded* generators are potentially important, since they differ materially from those for 'transmission-connected' generators, and therefore have the potential to affect the *type* of generation investment that occurs in the NZEM.

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1 Note that clause 40.2 of the Benchmark Agreement ostensibly requires such investments to meet the 'economic' limb of the GIT but, as noted in section 3.2.2, in practice a comprehensive cost-benefit analysis may not be undertaken.

Assessment of Existing Arrangements

Many features of the existing transmission pricing arrangements are fundamentally sound, and are consistent with the objectives set out above. For example, the arrangements ensure that system costs are recovered, and the nodal pricing and dynamic loss factor arrangements serve to minimise distortions to short-run operational signalling. The connection charging arrangements also provide additional locational signals by forcing connecting parties to trade off the additional costs of locating at various points with the additional costs of connection. The interconnection charging arrangements also provide appropriate incentives for off-take customers to reduce consumption at peak times in those regions that will soon require significant transmission investment.

However, the existing arrangements also exhibit a number of potential problems, namely:

- the combination of nodal prices, losses, deep connection charges and the GIT may not be sufficient to signal the long-run marginal cost (LRMC) of transmission investment;
- the HVDC charge is incapable of providing ***intra-island*** locational signals;
- the circumstances and manner in which the GIT is undertaken are potentially problematic – most notably, because each transmission investment is considered in isolation, critical interdependencies with other projects may be overlooked and so the wrong investment option selected;
- the existing 'deep' connection charging regime has the potential to distort the long-run investment cost signals associated with different generation alternatives, specifically:
  - because connection charges can vary substantially depending upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment signals can be created in some circumstances;
  - the arrangements for recovering the costs of 'shared' connection assets may give rise to significant step-changes in connection charges as 'beneficiaries' change over time, which can reduce certainty and further harm dynamic efficiency; and
  - the arrangements may give rise to 'first mover' problems, whereby individual generation proponents are unwilling to pay the deep connection charges to connect new generation locations;
- levying HVDC charges on the basis of South Island generators' historic peak injections (HAMI) is said by some South Island generators to distort their use of and investment in peaking capacity, specifically:
  - the HAMI charging parameter does *theoretically* provide incentives to withhold supply of peaking capacity, although the circumstances in which it will be profitable to do so seem likely to be infrequent;
  - the incidence of the HVDC charge may reduce incentives to invest in the South Island (particularly in peaking capacity), although this may well be symptomatic of efficient locational signalling; and
  - the HVDC charge also increases the likelihood that new investment will be undertaken by established incumbent South Island generators (notably Meridian).

In other words, the existing arrangements have their share of strengths and, importantly, some weaknesses that give rise to potentially beneficial options for reform.

High-Level Options for Reform

Introduce Further Locational Signals

It is apparent from the problem definition that industry and major consumer stakeholders would like to see a TPM that sends efficient locational signals, to the extent that such signals are not adequately provided elsewhere. The nodal pricing arrangements, when combined with the application of the GIT and deep connection charging, may not be capable of playing a sufficiently prominent role to prevent sub-optimal locational decisions by generators. Moreover, the HVDC charge is incapable of providing ***intra-island*** locational signals. In other words, there may be scope for the TPM to be modified in some manner so as to provide superior locational signals – particularly to generators. The high-level options for introducing further locational signals are summarised in the table below.

Summary of High-Level Options for Introducing Locational Signals

Characterisation of Grid	TPM Option	Key Issues
Structural south-north flow that will drive new investment in that 'highway'	§ Tilted Postage Stamp (TPS) methodology applied to generators § Residual charge on load based on RCPD § Shallow connection § No HVDC charge	Is the assumed structural characterisation valid?
'Bespoke' locational preferences, ie, focus on locations where load patterns are clear or on shorter-term investment requirements	§ 'Modified' TPS methodology applied to generators § Residual charge on load based on RCPD § Shallow connection § No HVDC charge	Would the estimated locational signals be sufficiently enduring?
Enduring characterisation not possible	§ Retain deep connection § No HVDC charge § Locational signals provided by nodal prices, deep connection and the GIT	Is there a feasible alternative to this 'default' position?

It follows that the critical decision facing the Steering Group is whether it is feasible to come to a settled view on an enduring characterisation of the transmission grid for a 10 to 20 year period, or a set of bespoke locational preferences over a similar period. In our view, Transpower is likely to be in the best position to establish an enduring characterisation of the grid, eg, based on its 10-year plus transmission development plan and the Electricity Commission's (EC's) Statement of Opportunities (SOO) scenarios. Assuming that an enduring characterisation of the grid can be made, the combination of Transpower's indicative investment programme and the SOO scenarios should provide the basis for determining the appropriate extent of the 'tilt', and any reset.

The table above illustrates that, if no enduring characterisation is possible – even in specific locations – then the process of estimating long-run costs and developing robust price signals is likely to become unworkable. In these circumstances, the costs associated with grid upgrades would then need to be recovered by means of a 'tax' that would be designed so as to be as efficient as possible.

The design and application of the GIT is particularly important under such an option. In consequence, it is likely to become more important to address potential shortcomings in the way in which the test is presently applied. In particular, if multiple transmission investments are intended principally to address the same problem, say, constraints in a particular importing region, then it would be beneficial for the interdependencies between these projects to be recognised in some way when undertaking the GIT. However, such an exercise is beyond the scope of this study, and has not been explored further in this report.

HVDC Charges

The justification for retaining the HVDC charge does not appear to be strong. Specifically, there appears to be good reasons to replace the charge with a TPS methodology capable of delivering a superior locational signal. Alternatively, if a TPS methodology cannot feasibly be implemented, then the same obstacles are likely to preclude one having any confidence in the locational signal being provided by the current HVDC charge. These considerations suggest that it should be removed, ie:

§ if a TPS methodology is implemented, the HVDC charge could be incorporated entirely into the interconnection charge and recovered from generators and load; and

§ if a TPS methodology is *not* implemented, the HVDC charge could be either:

  – incorporated entirely into the interconnection charge; or

  – the costs associated with the Pole 1 replacement could be incorporated into the interconnection charge, with the remainder being recovered from South Island generators as a 'legacy charge'.

If some form of HVDC charge remains nonetheless (either the charge as presently formulated, or a 'legacy' charge), the most sensible alternative to a HAMI-based charge is a parameter based on a measure of capacity that is not dependent on usage, eg, nameplate capacity. However, we are not convinced that there are any fundamental problems with the HAMI-based charging parameter that might necessitate such a change.

Connection Charges

We cannot be confident that a *substantial* departure from the existing deep connection charging arrangements to implement, say, shallower connection charges or a 'but for' test, would deliver a material improvement upon the status quo. There are likely to be some advantages, but the potential disadvantages may be even greater. We note that the case for any shift to shallow connection charges is likely to be stronger if further locational pricing signals were to be implemented through the interconnection charge, as implied by the high-level options summarised in the table above.

It is possible that more modest reforms may be capable of addressing at least some of the more significant distortions created by the existing arrangements, without necessitating fundamental change, for example:

- levelling the playing field between transmission-connected generation and embedded generation by:
  - modifying the *Electricity Governance (Connection of Distributed Generation) Regulations 2007* (DGRs) so as to remove the requirement upon distributors to compensate embedded generators for avoided transmission costs;[2] and
  - allocating ‘shared’ connection costs to transmission-connected and embedded generators alike based on their AMI injections at the grid exit point (GXP);
- revisiting the rules relating to generators (and distributors) constructing, and assuming ownership of transmission links, including:
  - preventing generators from owning connection assets (or entering into analogous contractual arrangements with distribution companies), ie, requiring that all connection assets ultimately be owned by Transpower;
  - putting in place formal arrangements in the TPM to require ‘first-movers’ to be compensated by ‘second- and third-movers’ that connect subsequently to assets that have been funded by the first mover for a period;
- by reforming the application of the GIT to connection assets in two ways:
  - through Transpower requiring parties to connect at the most sensible location from an overall system perspective, where more than one location is technically possible, ie, by exercising the discretion provided by the Benchmark Agreement; and
  - allowing, in certain circumstances, for a new connection investment to be considered part of the interconnected network if the economic limb of the GIT is met, and socialising the attendant costs across multiple grid users.

However, there was not a consensus among the Working Group regarding the materiality of the issues that the suite of changes listed above would be intended to address. For these reasons, although the Working Group considers that it will need to be mindful of these issues in developing any option in the subsequent project phase, it does not consider that they warrant further exploration in the near term.

Introduction of FTRs

Designing and issuing FTRs would entail substantial additional regulatory costs, and would not obviate the need for the existing regulated transmission pricing and investment arrangements. However, it would also offer some potential benefits, including reducing (albeit perhaps not by very much) the proportion of transmission costs that must be socialised,

[2] The alternative would be to put in place other mechanisms such as network support payments to allow transmission-connected generators (and potentially other non-network alternatives) to receive equivalent payments.

and allowing market participants to hedge their volatile congestion costs. Ultimately it is a matter of degree. Our preliminary view is that there is a strong possibility that the additional regulatory costs may outweigh the potential advantages, at least in terms of transmission pricing (as distinct from hedging benefits), in which case FTRs should not be introduced.

1. Introduction

The purpose of the Working Group's review is to explore ways in which to improve the efficiency of electricity transmission pricing arrangements in the New Zealand Electricity Market (NZEM). The touchstone for any proposed options for reform should be the potential for *material improvement* upon the existing arrangements, ie, the enhancement of economic efficiency through altering the *commercial incentives* facing market participants and ultimately their decisions/conduct, so as to produce more desirable outcomes.

Change for the sake of change is not an objective. In particular, options that simply alter the incidence of transmission changes (which is inevitable) to the financial advantage of one party or another, but do *not* give rise to any material improvement, will simply impose needless additional regulatory costs. Ultimately, reform will only deliver economic benefits if *desirable behavioural change* is brought about. A reform option must lead to real changes in the commercial behaviour/decisions of the relevant parties, in the manner intended.

1.1. Objectives

At the most basic level, the fundamental objective of any transmission pricing arrangements should be to encourage efficient *use of* and *investment in* the transmission network (and associated electricity industry infrastructure). This overall objective can, in turn, be separated into shorter- and longer-term operational objectives. Since transmission is both a substitute (albeit imperfect[3]) for and complement to generation, achieving these objectives requires closely coordinated action by participants in both the generation and transmission sectors.[4]

The principal mechanism for achieving an efficient degree of coordination between transmission and generation in a vertically-separated electricity industry such as the NZEM is through *price* signals. In a disaggregated industry in which generators and consumers react to market signals, the level and structure of transmission charges has a potentially significant effect on network use and, to a lesser extent, transmission investment. Transmission charges may also affect the *locational choices* of new generation and energy intensive users, as well as potentially influencing the bidding conduct of generators.

Setting such charges at the right level is critical for ensuring the efficient use of and investment in the transmission network. It is also one of the most challenging problems facing regulators. In particular, we understand that industry and major consumer stakeholders would like to see a transmission pricing methodology that:

- sends efficient locational signals (assuming these signals are not adequately provided elsewhere);
- sends capacity signals to encourage, among other things, efficient demand-side response;

[3] Transmission is not a *perfect* substitute for generation, since it does not itself provide energy; strictly, it is a substitute for producing energy at the location it is needed, as distinct from producing energy somewhere else.

[4] Furthermore, since gas transmission is a substitute for electricity transmission, efficient operation and investment decisions in both the gas and electricity industries requires well coordinated action by participants in both the gas and electricity sectors. However, we do not explore any further the interdependencies between the gas and electricity sectors in this paper.

- sends efficient signals as to the timing and nature (as well as location, identified above) of new generation development; and
- endures in line with the time frames for investment decisions so as to provide certainty as to the nature and extent of those price signals to all stakeholders.

In order to identify potential options for change to the arrangements that are most likely to meet these objectives, it is necessary first to understand the arrangements that are *currently* in place and, critically, to understand the incentives (both positive and negative, or productive and counter-productive) that are created by them. With this in mind, we set out our proposed approach to identifying potential options for reform below.

1.2. Our Approach

Given the objective of identifying reform options that represent *material improvement* upon the status quo by producing desirable behaviour change, rather than simply giving rise to wealth transfers with no desirable consequences for efficiency. Accordingly, at the highest level our approach comprises two steps:

Step One: Consider the extent to which the *existing* transmission pricing arrangements are consistent with the fundamental objective and support the achievement of efficient outcomes. The Working and Steering Groups have a very important role to play in the process of identifying and understanding the various incentives that arise under the current arrangements, and this itself is an important objective of this paper.

Step Two: For those aspects of the existing arrangements that are not demonstrably consistent with the fundamental objective, consider whether any potential reforms may give rise to more efficient outcomes, thereby representing a material improvement. In this process, the Working and Steering Groups have a similarly critical role in identifying the incentives likely to arise under the various reform options set out in this paper.

The remainder of this report is structured as follows:

- **section two** reflects briefly upon past developments in the New Zealand market and the practical complexities arising from the underlying characteristics of the transmission network that have hindered attempts to introduce ‘market-based’ investment through a financial transmission rights (FTR) framework, including the attendant lessons;
- **section three** begins ‘step one’ by providing a high-level description of the current transmission pricing arrangements contained in the *Electricity Governance Rules* and Transpower’s transmission pricing methodology (TPM);
- **section four** assesses the extent to which the existing transmission pricing arrangements provide adequate signals to locate new generation and/or load efficiently, or to make efficient use of existing infrastructure;
- **section five** begins ‘step two’ by scoping out preliminary options for reform of the current transmission pricing arrangements, targeted at addressing the perceived problematical aspects of the existing TPM; and

- **section six** summarises the high-level options for consideration by the Steering Committee.

In producing this report we have made a number of working assumptions concerning several aspects of the market arrangements that are outside our terms of reference. Most notably, in drawing our preliminary conclusions we have not sought to address matters arising from the existence of any potential market power in the wholesale electricity market, including through changes to the nodal pricing arrangements. We have assumed that the current industry structure will remain broadly intact for the foreseeable future, and that Transpower will still need to undertake the grid investment test (GIT) before investing in core and regional assets. Finally, political and social considerations are transition issues and are to be considered later. In particular, wealth transfers are considered only to the extent that such transfers may have potential consequences for dynamic efficiency.

2. The Economics of Transmission

Before deciding how best to move forward, it is instructive to examine the basic economics of transmission, including the formidable challenges arising from its underlying characteristics. Once these practical complexities are understood it is easier to appreciate why it is that the existing arrangements have been put in place, why efforts to introduce ‘market-based’ transmission investment and pricing frameworks in New Zealand have been unsuccessful, and some of the challenges that would need to be overcome in order to provide ‘efficient locational signals’, consistent with the problem definition. Inevitably, the fundamental economics and the underlying practicalities of transmission pricing and investment will have a substantial bearing on the feasibility of potential reforms.

2.1. The Basic Economics

In simple terms, electricity transmission networks move electrical energy from one location to another. In the short-run, physical investment in the transmission network is fixed. Indeed, the majority of Transpower’s regulated revenue – and hence most of what needs to be recovered through its regulated transmission prices – comprises a return on its existing, sunk network assets. In consequence, the short-run costs of transmission consist of the physical energy losses incurred during transmission and the ‘opportunity cost’ of any constraints or network congestion.

When a transmission network is congested, the short-run alternative is to deploy more expensive generation from a different location. The short-run marginal cost of transmission is therefore determined by the cost difference between the cheaper generation and that which must be used because of the network constraint. In New Zealand, wholesale spot prices are based on *locational marginal prices* (LMP), so the short-run marginal cost of transmission between two nodes is represented by the ***difference in the spot prices at the two nodes***, which will reflect the cost of transmission losses and transmission constraints.[5] Box 2.1 illustrates the short run costs of transmission, and their link to optimal dispatch and spot market prices.

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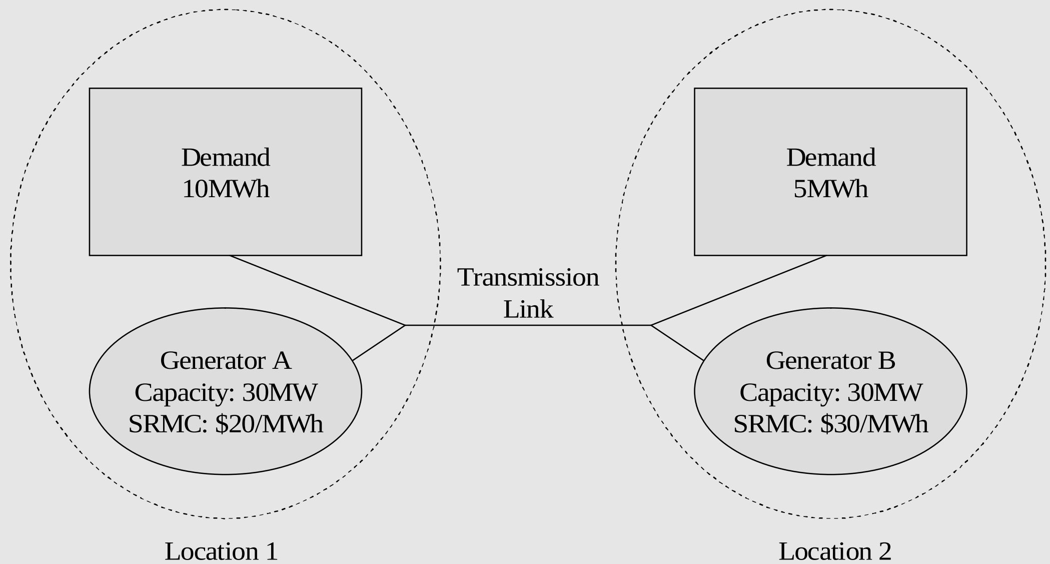
[5] The spot wholesale electricity market, also known as the New Zealand Electricity Market (NZEM), began full operation on 1 October 1996. Spot prices are calculated using the offers and bids made by generators and customers. Specifically:

- injection customers receive the portion of loss and constraint rentals allocated to their connection assets, ie, the assets required to connect them to the ‘shared’ interconnected grid;
- the spot price at each of the 220 ‘grid nodes’ is set equal to the marginal cost, calculated based on offer prices, of supplying an additional increment of demand at each node, modified by adjustments to take account of the costs of transmission losses and constraints; and
- all dispatched generators are then paid a price based on the market clearing price at their location, independent of their original offer price.

Nodal prices therefore incorporate the costs of losses in particular locations throughout the transmission system, as well as the costs of congestion. However, note that this only partially internalises the costs of congestion since nodal prices may not be free to increase sufficiently to limit demand in the event of (generator) congestion.

Box 2.1
Spot Prices and the Short-run Cost of Transmission



If transmission is costless, optimal dispatch will involve accepting the lowest cost generator until demand is satisfied. In this case, generator A will be dispatched first and it will be able to satisfy demand in both locations 1 and 2. Generator B will not be dispatched. Assuming that generators bid at their short-run marginal cost (SRMC), the spot price in each location will be $20/MWh.

But transmission is *not* costless. First, there is the cost of energy losses as power flows along the wires. If the cost of energy losses is less than $10/MWh, costs will still be minimised by dispatching generator A to both locations. If the marginal energy loss is $5/MWh, then the marginal cost of energy in location 1 is $20/MWh, equal to the generation cost. The marginal cost of energy in location 2, however, has risen to $25/MWh. If spot prices reflect the cost of losses, then the spot prices in the two locations will diverge. The marginal cost of transmission is equal to the difference in spot price between the two locations, ie, $5/MWh. In other words, transmission losses give rise to 'transmission rentals' that must be allocated in some way during the settlement process.[6]

Now imagine there is a transmission constraint between the two locations. Generator A can no longer serve the full demand in location 2 because of the transmission constraint. Therefore generator B must be called upon to generate. The marginal cost of generation is now $20/MWh in location 1, and $30/MWh in location 2. The constraint is an additional transmission cost – it is an 'opportunity cost' of not being able to use the cheapest generation source – and gives rise to a further 'transmission rental' that must be reconciled during the settlement process. Again, the short run cost of transmission will be reflected in the difference between the spot prices in the two locations, which now reflects the cost of losses, plus the cost of constraints.

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[6] Note that this assumes that the marginal rate of losses (in this example, 5/20 = 25%) is higher than the *average* rate of losses. For a buyer at location 2 procuring supply from Generator A at location 1, paying the loss rental component has the same effect as if it had purchased a greater quantity at location 1 at a lower price, and incurred the actual losses on the transmission link. Similarly, for Generator A at location 1, receiving the loss rental has the same effect as if it had sold a reduced quantity at location 2 at a higher price and injected sufficient energy to make up for actual losses in the transmission link.

During the wholesale market settlement process, transmission rentals (ie, loss and constraint rentals) for the entire transmission network are bundled together and allocated amongst market participants. The allocation of transmission rentals to customers is determined by the class of assets that generates the rentals – connection assets, interconnection assets or HVDC assets (which are described in more detail in section 3). Specifically:

- injection customers receive the portion of rentals allocated to their connection assets, ie, the assets required to connect them to the 'shared' interconnected grid;
- South Island generators also receive a portion of the rentals produced by the HVDC link – the link that connects the interconnected grids in the North and South Islands – in proportion to their contribution to total South Island historical anytime maximum injection (HAMI); and
- off-take customers (ie, distribution companies and directly-connected customers) receive the portion of the rentals produced by their connection assets and the portion of rentals produced by interconnection assets corresponding to their contribution to the payment of interconnection charges as determined by the TPM.

In summary, the short-run costs of transmission are those that vary with respect to the flows of energy over *existing facilities*, ie, the scheduling and dispatch of generation and load. Importantly, these costs include transmission losses and constraints, which each give rise to rentals that must be allocated amongst customers during the settlement process. However, in the long run, *all costs* are variable. The existing network needs to be maintained, and capacity can be expanded. The long-run costs of transmission are therefore those associated with maintaining and/or expanding the network.

There is a strong link between the short-run costs of transmission, the long-run cost, and efficient investment in both transmission and generation assets. In the first instance, increased transmission demand can be met through increased energy losses across the network. As congestion occurs, alternative (more expensive) generation must be sought. In the long-run, absent generation investment, the cost of losses and constraints might increase until the point where it is cheaper to augment the network. From an economic perspective, therefore, the conditions for optimal expansion of the transmission network are that:

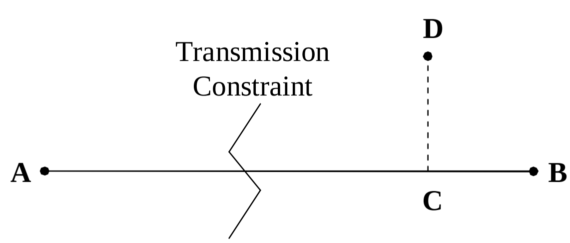
- additional transmission capacity should be built only if the total savings in the cost of generation (and demand management) exceed the additional transmission costs; and
- additional capacity should be sized such that the marginal cost of generation savings and loss reductions (indicated by the difference in future spot prices – or generation costs – at different locations) equals the marginal cost of building additional capacity.

In other words, in principle, investment will be efficient up to the point where the cost of one more unit of transmission capacity – the long-run marginal cost (LRMC) – is equal to the avoided cost of future constraints and losses – the short-run marginal cost (SRMC). These economic characteristics of transmission apply irrespective of the market framework that is put in place.[7]

The initial thinking in New Zealand (and elsewhere) was that the existence of full nodal pricing would give rise to the possibility of ***market-driven*** pricing and investment, whereby network users would have an incentive to invest in new transmission capacity themselves. In principle, users (or groups of users) have an incentive to invest if the cost (to them) of augmentation is expected to be less than the continuing costs (to them) of the losses and constraints that will otherwise be incurred.[8] Indeed, Transpower does not have a statutory monopoly of transmission service in New Zealand, which leaves open the possibility of different operators investing independently in transmission infrastructure.

Such investors need not receive a regulated revenue stream. Rather, the motivation for investment is to avoid the costs of future losses and congestion. However, to ensure that investors do not lose the benefits of their investment, they must receive a right to any network 'congestion rents', ie, revenue that arises from a divergence in the spot price between locations, should the link in which they have invested become congested in the future. Such rights might be 'physical rights' to the dedicated infrastructure, or FTRs that are purely financial in nature. The consequence of such investment would be to reduce (or potentially eliminate), the need to undertake centrally planned transmission investment, and to reduce (or potentially eliminate) the need to fund such investment through regulated transmission prices.

To illustrate, suppose that a brand new transmission network was being built 'from scratch' that comprised only two-nodes. Suppose also that the annualised cost of financing that network (ie, operating and maintenance costs and a return on and of capital) was $10 million for an 110kV connection. In principle, rather than calculating that annualised cost, and recovering a corresponding quantum of revenue from transmission customers by means of regulated transmission prices (which essentially is the approach taken in New Zealand at present), an alternative might be to define and allocate an FTR for the link between nodes A and B. For example, the initial allocation of the FTR could be by means of an auction, with the right being provided to purchasers in perpetuity. Those purchasers would then be required to pay an annual fee to hold that right, with this amount covering the annualised capital cost of the infrastructure.



[7] In other words, the costs of transmission and the rules for efficient investment are the same whether or not a competitive energy market exists, whether or not energy markets involve full nodal pricing, and whether or not transmission pricing and investment is planned centrally or determined using 'market-based' incentives.

[8] As noted below, in order to provide the right incentives for efficient investment, network users must face the costs of congestion and losses, which *theoretically* is achievable through LMP, but is extremely complex to achieve in practice.

Provided that users (or groups of users) anticipate that an annual cost of $10m is less than the estimated future annual LMP price differential (losses[9] and congestion rents) between A and B for usage up to the capacity of that line, then they should be willing to pay up to $10m per annum to secure the FTR. Note that as part of estimating future rents, investors will need a clear understanding regarding future additional transmission expansion, and in particular would expect that additional investment in the A to B link would not occur until such time as loss and constraint rentals between the two nodes rose again to be greater than the annualised cost of expanding the link. To recap:[10]

- FTRs are defined and allocated to investors that expand the transmission system;
- the FTRs are valuable because they allow owners to buy energy at the locational price at one end of the link in question, and sell it back at the locational price at the other end; and
- the rights will be valuable when transmission is scarce (ie, when there is congestion) and so people will have incentives to build when and where transmission is needed.

The expectation was that this form of 'market-based' investment may become a central feature of the New Zealand electricity market landscape, and that this would affect fundamentally transmission pricing arrangements. To this end, in 2002 the industry and the Government canvassed extensively the possibility of introducing FTRs in order to create property rights that would improve the potential for market-led transmission investment.[11] However, FTRs ultimately were ***not*** introduced and, to date, user-driven transmission investment has been limited to connection assets, and there have been no transmission investments undertaken by independent operators.[12]

Rather, it is reasonable to suggest that the existing arrangements for transmission pricing and investment (which are summarised in section 3) differ markedly to those that were envisaged in the early 1990s, and as recently as five- to seven-years ago. This is perhaps not surprising once the formidable ***practical*** challenges arising from other economic characteristics of transmission are fully appreciated.[13] These factors serve to somewhat undermine the appeal of an FTR-based framework which, although attractive ***in principle***, cannot obviate the continuing need for some degree of centralised transmission planning and regulated pricing ***in practice***.

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9 Note that FTRs are not normally defined inclusive of the collection of losses rents (rather, just congestion rents) but for illustrative purposes losses are included in this example.

10 For a comprehensive description, see: H. Fraser, 'Can FERC's Standard Market Design Work in Large RTOs?', *Electricity Journal*, Volume 15, Number 6, July 2002 , pp19-30.

11 Such rights were intended also to allow market participants to hedge locational price risk resulting from transmission congestion. See: E Grant Read, *Financial Transmission Rights for New Zealand: Issues and Alternatives*, prepared for the New Zealand Ministry of Economic Development, 8 May 2002.

12 See Appendix D for a more comprehensive discussion of market-based approaches to transmission investment.

13 Ibid.

2.2. Practical Complexities

Many well recognised factors complicate the potential for market-based mechanisms for transmission expansion in ***practice***.[14] First, there are scale economies and an associated 'free-riding' problem:

- Transmission investments are 'lumpy'. They exhibit significant economies of scale – once the land has been purchased and the towers built, there is not much difference in cost between a low capacity line and a high capacity line. Because it is not practicable to build transmission lines in increments of 1MW, in most instances high capacity lines are constructed.
- Because lines tend to be large and infrequently built, once they are built they tend to eliminate congestion.
- If they eliminate congestion, then the transmission rights will have no value. This is not a problem per se – even if congestion is fully eliminated, the investment might still be cost-effective because it allows less expensive power to substitute for more expensive alternatives. Uncongested transmission allows cheap but previously isolated generators get to sell their power into the same market at the same prices as everyone else.
- However, these scale effects mean that there are some strong incentives for 'free riding'. If a generator stands to benefit from congestion being eliminated, it may be better off waiting and hoping that someone else builds transmission first in order to avoid the cost of building. Of course, if everyone thinks that way there will be a stalemate and nothing will be built.
- Many potential transmission investments are very large, and may be bigger in scale than the individual market participants, and so coalitions of interested parties may be necessary. The need for coalition serves to exacerbate the free riding problem.

Other problems also exist:

- Building any transmission line can actually increase network capacity by more than the capacity of the line because of network effects. It may also decrease capacity in some parts of the system. The net amount of capacity increase associated with a transmission right is a contentious issue that inevitably involves some system operator judgement, and therefore some opaqueness.
- The theory of market-driven investment remains untested in the real world. Given all the uncertainties, including how long it takes to get the necessary approvals to build transmission lines, to form coalitions, and to wait for long-term market prices to signal the value of new transmission, there is a fear that investment will come too late, and that the reward of transmission rights will not induce enough capacity.
- Finally, with transmission investment there may be more than private benefits at stake. Increased transmission can reduce market power and increase network reliability. There are also likely to be valid national security interests to 'err on the side of caution' by

[14] For a comprehensive discussion, see: H. Fraser, 'Transmission Business Model', in *Making Competition Work in Electricity*, ed, S. Hunt, New York, Wiley, 2002, p199; and H. Fraser, 'Can FERC's Standard Market Design Work in Large RTOs?', *Electricity Journal*, Volume 15, Number 6, July 2002 , pp19-30.

investing in new capacity before nodal prices increase reflect the costs of congestion. So, even if it was possible to solve all of the other problems of market-based transmission investment, in practice, there will always be a role for centrally planned transmission.

The consequence of these myriad complications is that a fully decentralised 'market-based' model can never be solely relied upon to drive transmission planning, investment and, ultimately, pricing. It should therefore have come as little surprise that pure, market-based investment has not been forthcoming in New Zealand, particularly in light of the highly collaborative self-governance arrangements in place prior to 2003.[15] Put simply, an FTR-based framework *cannot ever* eliminate the need for regulation to play an important role in ensuring efficient transmission expansion and pricing.[16]

Returning to the simple example from above, because of the practical complexities described above, any auction of FTRs between nodes A and B would be highly unlikely to recover the $10m annualised cost of financing the 110kV connection. Free-rider problems may hamper the formation of bidding consortia, and even if they did not, users would not be prepared to pay $10m, since the estimated future annual LMP price differentials (losses and congestion rents) between A and B would never reach $10m per annum. For these reasons, the complexities set out above mean that:

§ there will always be a need to recover at least a proportion of the costs associated with the transmission network from users through a regulated transmission pricing framework, where at least some of those prices are levied upon multiple users (or 'socialised'); and

§ there will continue to be a role for centralised transmission planning, eg, through the operation of an 'investment test'.

A growing recognition of these practical complications was perhaps one of the precipitating factors in the development of several aspects of the *existing* transmission pricing arrangements, which are outlined in more detail in section 3, including:

§ the development and subsequent refinement by Transpower of a transmission pricing methodology (TPM) for connection assets, interconnection assets and the HVDC link;

§ the development by the Electricity Commission of the GIT; and

§ the ongoing development by Transpower of investment contracts to recover the costs associated with providing new connection assets from individual connecting customers.

Of course, these practical complexities do not disappear within a ***regulated*** transmission pricing and investment framework. For example, one of the most significant challenges facing regulators today, and a prominent feature of the problem definition set out in the introductory section, is whether it is both desirable and practicable for ***regulated*** transmission pricing arrangements to 'send efficient locational signals' (to the extent that they are not

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15 The inevitable winners and losers involved in such processes meant that expecting to achieve a consensus amongst industry participants on key issues such as the development of FTRs was, in retrospect, perhaps overly optimistic – and so it proved.

16 To be clear, although the issuance of FTRs cannot ever provide a *substitute* for the existing regulated transmission pricing and investment arrangements this is not to say that FTR products cannot potentially deliver a number of *other* potential ancillary benefits, which we discuss in see section 6.4.

provided elsewhere). The following section explains why it is that locational signals through transmission prices encounters many of the same complexities posed by the basic economics of transmission systems, described above.

2.3. Providing 'Locational Signals'

The level and structure of transmission charges may affect the *locational choices* of new generation and energy intensive users, as well as potentially influencing the bidding conduct of generators. One of the most challenging questions in determining a framework for regulating transmission services is whether it is possible to design and incorporate locational signals in charges for the service so as to improve the efficient use of and investment in transmission network infrastructure. This section addresses the question of what such a locational signal might entail, and what it should be designed to achieve.

The fundamental purpose of providing a locational signal is to change behaviour in a desirable way by altering commercial incentives. The objective is for that modified conduct to reduce the future transmission capital expenditure that is needed so as to improve the use of and investment in the grid, without giving rise to investment or operational consequences elsewhere (such as in the generation market) that are more costly than the transmission expenditure that is saved. In other words, a locational pricing signal should:

- change in a material way the locational decisions made by generators and/or load, otherwise such a signal will not have brought about any efficiency gains; and
- as a consequence, reduce or defer transmission costs that would otherwise be incurred absent such a signal so as to reduce the overall costs of delivered electricity.

Preliminary forecasts of the upgrades required for the New Zealand grid 'main trunk'indicate that Transpower has a significant, forward-looking investment program in the North Island – particularly in the central- to upper-North Island – that we understand to be caused in large part by the expectation that generators will locate away from major load centres. Indeed, $3b is forecast to be spent on the interconnected AC network north of Bunnythorpe alone between 2009 and 2035 (for further details see section 5.1). Clearly this is a significant potential investment program.[17]

This suggests that if the TPM could be designed so as to provide generators and/or load with incentives to locate in places that might avoid or defer the need for this substantial forward-looking investment, this would potentially be *very beneficial*. In general terms, the types of behaviour that one might seek to elicit through locational price signals provided by means of the TPM include some or all of the following:

- encouraging generators and load to locate near to an existing grid exit point so as to minimise the costs associated with connecting those customers to the interconnected network; and/or
- encouraging generators to build new plant in congested locations so as to reduce or defer the need to invest in additional interconnection network capacity to transport generation

[17] Note that this estimate is only indicative, and subject to a number of caveats set out in footnote 101.

from more remote locations or, equally, discouraging generators from building in locations that are distant from congested load centres, eg, a generator that locates at, say, Albany, might be expected to avoid or defer transmission investment than a generator that locates at Benmore; and/or

- encouraging load to locate in uncongested regions so as to reduce or defer the need to invest in additional interconnection network capacity to serve those customers or, again, discouraging load from locating in congested areas; and/or
- encouraging load to reduce contributions to peak demand in congested regions so as to reduce or defer the need to upgrade transmission capacity to serve growing peak demand in those areas – ideally without distorting consumption in uncongested locations.

However, enticing such behaviour can be difficult. First, it must first be remembered that the investment decisions of generators and off-take customers will be influenced by a range of factors ***besides electricity prices***. Generators may decide to locate their plants based primarily on the availability of certain fuels, such as access to fossil fuel, geothermal or wind energy. For these types of generators, the locational variation in access to energy sources may greatly exceed even the largest feasible locational differentiation in transmission charges.[18] Similarly, locational decisions may be influenced by pragmatic considerations such as the need to obtain the appropriate consents under the ***Resource Management Act 1991***.[19]

Transmission prices are likely to have *even less effect* on the locational investment decisions of load. Indeed, the elasticity of off-take customers' investment decisions with respect to transmission charges is likely to be relatively low (or 'inelastic'). Although there may be exceptions, it is hard to imagine that the locational decisions of, say, large industrial customers would be influenced to a significant extent by anticipated transmission charges *in the vast majority of circumstances*, including because:

- such decisions will be influenced by many other factors that are likely to be considerably more important, including access to markets, proximity of customers, access to raw materials and labour, the location of transport nodes – forecast transmission charges are unlikely to be a substantive consideration in most instances; and
- forecast transmission charges represent only a modest proportion of total energy charges to load, which in most cases are likely to represent a modest proportion of total input costs, eg, compared to expenses such as rent.

Nevertheless, it is possible to design the transmission pricing arrangements so as to provide an incentive for large industrial customers to change their behaviour in a desirable way *once the initial locational decision has been made*. For example, it is possible to provide incentives to reduce consumption at peak times in locations that are, or are likely to be,

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[18] In these circumstances, transmission charges have little or no effect on overall economic efficiency. Provided the price of these external factors is determined in competitive markets, we can assume that those prices reflect the marginal cost of the relevant inputs. Any resulting locational incentive arising from those input prices is therefore efficient and can be put to one side.

[19] For example, if a potential location is covered by an existing consent, and an alternative location would require a new consent to be obtained this may be a decisive factor in selecting the former location if the consent approval process is likely to be costly and protracted.

susceptible to congestion. The existing interconnection charging arrangements for load described in section 3.1.2 are a good example. The current charge, which is based on off-take customers' contributions to the average regional coincident peak demand in a region, provides load with an incentive to reduce peak demand in those areas in which significant transmission investment is forecast.

If it is accepted that the purpose of providing a locational price signal is to change customer behaviour so as to avoid or defer transmission expenditure, the insensitivity of the locational decisions of load to potential variations in transmission charges would seem to lead to the conclusion that ***prospective generators*** and ***existing load*** should be the primary focus of any such signals, since they are more likely to respond.[20] Of course, the subsequent and more difficult question is ***deciding what locational signal to send***.

In simple terms, the theoretical 'efficient investment rule' previously discussed[21] suggests that an 'efficient locational signal' might involve charging a customer a price that reflects, to the greatest extent possible, the forward-looking LRMC of the transmission investment required to serve that customer in that particular location (to the extent that this is not reflected through the nodal pricing arrangements, as we discuss in section 4.1). However, although straightforward *at the level of principle*, there are some significant difficulties associated with designing a pricing methodology to reflect this objective ***in practice***.

Consider a generator that is deciding whether to locate plant in Fiordland, many hundreds of kilometres away from the nearest load centre, or in Otahuhu, adjacent to New Zealand's largest load centre. The long-run transmission cost associated with serving the customer in these two locations is unlikely to be the same. Indeed, a Fiordland plant may contribute to substantial additional and ongoing transmission costs, whereas an Otahuhu plant may ***avoid or defer*** transmission investment that might otherwise be required to transport more remote generation to load in and surrounding Auckland. To the extent the cost differentials described above are not reflected elsewhere, ideally the TPM should cause the generator ***not to be indifferent*** between the two locations, holding other factors constant (such as location of fuel, losses, availability of resource consents, etc).

Intuitively, one might expect the TPM to require the generator to pay ***more*** in aggregate if it locates in the deep-South than if it builds in Auckland to reflect the significantly higher transmission costs required to serve it – the objective being to discourage generators from building in remote locations. But ***how much more***? Unfortunately, this is not a simple question to answer. Again, economic theory suggests that the overall price difference between the two locations should reflect the ***LRMC*** differential that is not already reflected in the ***nodal price*** differential, ie, the 'gap' between LRMC and SRMC. However, this rule is not easy to implement because the LRMC of the transmission capacity needed to serve any particular location ***changes over time*** as new capacity is added.

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[20] Although transmission prices will be immaterial to some generation location decisions, in other circumstances, the pricing signals provided by the various wholesale and transmission pricing arrangements may play a decisive role.

[21] Namely, that investment will be efficient when the LRMC of new transmission is equal to the avoided costs of future constraints and losses (the SRMC).

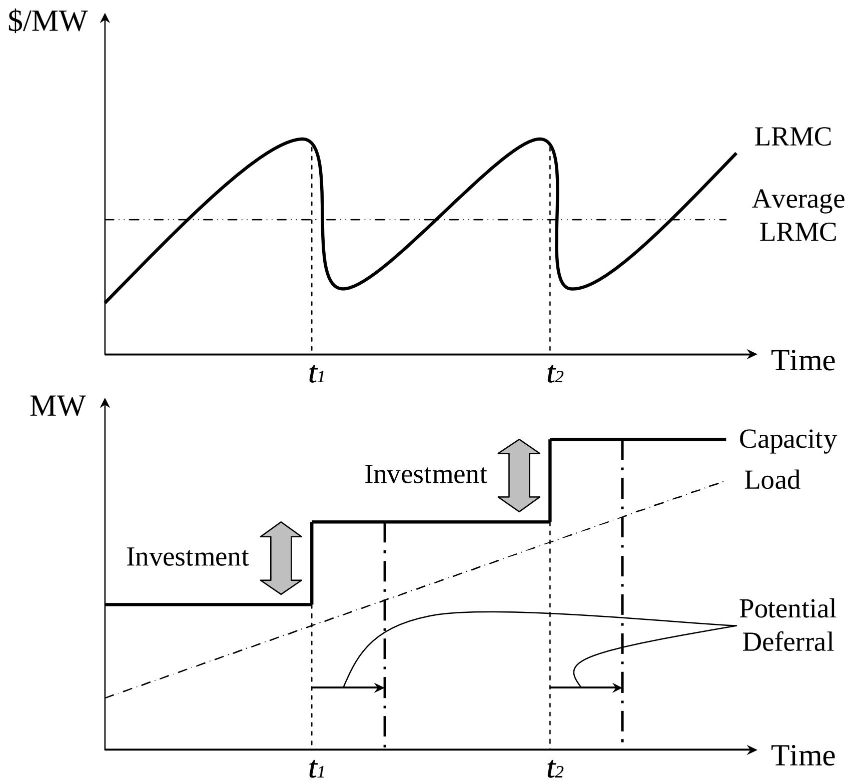
Because it is most efficient (due to economies of scale) for new transmission capacity to be added in 'lumpy' units, this gives rise to time-dependent fluctuations in the LRMC of transmission network capacity. By way of illustration, Figure 2.1 displays the stylised investment profile of a typical transmission link between two nodes, and the associated LRMC of that capacity over time. It shows that:

- in the years immediately following a new investment (ie, the years following t_1 and t_2) the LRMC of the next increment to capacity is low, because the value of any potential deferral of that future capacity requirement (say, through more efficient generator location decisions) is relatively low due to the effect of discounting.[22] An LRMC-based price that reflected such circumstances at that time would therefore tend to encourage the use of that infrastructure; and
- as spare capacity declines over time and the need to invest in new capacity approaches (ie, the years prior to t_1 and t_2), the LRMC of the next increment to capacity increases, because the value created through any potential deferral higher is closer in time and so less (negatively) affected by discounting. An LRMC-based price at that time would desirably discourage the use of that infrastructure, thereby delaying the imminent need for new capacity.

The *time horizon* is therefore critical. Leading up to an augmentation, Transpower *could* set attractive transmission prices (or design *payments*) for generators to build plant (eg, in Auckland), and/or set very high prices for off-take customers to discourage load growth in a location. However, just as it is impracticable to build transmission lines in increments of 1MW, it is also difficult constantly to alter transmission prices over time to reflect then prevailing LRMC at any particular location. Such an approach may result in significant changes in transmission prices – both between locations and over time as load flows change. Inevitably, it would also lead to ongoing debates amongst industry participants regarding the price signals that are most appropriate at a particular point in time.

[22] In other words, the value today of deferring by one year a $1b investment expected to be made in 12-months' time is much greater than the value today of that same one year deferral applied to a $1b investment expected to be made in 10 years' time.

Figure 2.1
LRMC, Load and Capacity over Time



In other words, in designing any locational price signal it is likely to be necessary to come to a view on where one might feasibly introduce a ***durable*** signal that will not need to be regularly changed (eg, annually) as market circumstances develop. For example, it is likely to be more appropriate to be guided by, say, an estimate of the ***average*** LRMC of forecast transmission requirements in the North Island versus the South Island over a ***20- to 30-year period***, rather than focussing on a large number of more specific locations over a shorter timeframe. Although such an approach would, by definition, under- or over-estimate the ***current*** LRMC of capacity at any point in time in a particular location, it is likely to provide a more stable signal ***over the longer-term.***

In summary, the purpose of providing a locational signal in the TPM would be to change in a material way the decisions made by generators and/or load so as to reduce or defer transmission costs that would otherwise be incurred. However, designing and implementing such a signal involves coming to a view on many challenging issues, such as what behaviour one wishes to encourage, the appropriate timeframe for consideration, whom to charge and the magnitude of such charges. All of these critical decisions will be influenced by the practical complexities posed by the basic economics of transmission systems. In the sections that follow we examine whether it is necessary to provide such signals and how one might go about designing and implementing such arrangements in the TPM.

2.4. Summary

The many formidable challenges arising from the underlying economic characteristics of transmission networks have hindered efforts to put in place 'market-based' transmission investment and pricing frameworks in New Zealand, and also pose challenging problems for the design of ***regulated*** transmission pricing arrangements – particularly any introduction of locational price signals. Dealing with these, and the many other practical complexities surrounding the fundamental economics of transmission networks, pose some of the most challenging questions facing electricity industry participants today.

Unfortunately, there are no clear, straightforward answers to these questions, and all of the potential reform options that we pose in this report necessarily involve trade-offs. Inevitably, the fundamental economics and the underlying practicalities of transmission pricing and investment will have a substantial bearing on the feasibility of potential reforms. Before turning to consider how best to address these complexities in a manageable way, and to manage the associated trade-offs, it is first necessary to consider the ***existing*** transmission pricing arrangements. These are summarised in the following section.

3. Current Transmission Pricing Arrangements

In 2003, the Government put in place new governance arrangements that superseded the previous industry self-governance processes. The Government Policy Statement (GPS) on Electricity Governance set out the responsibilities of the (then newly formed) Electricity Commission (the Board). This led to the introduction of Part F of the *Electricity Governance Rules* (EGRs), which set out the principles for transmission pricing and the process that the Board was required to follow to develop a transmission pricing methodology (TPM) to be incorporated into the Rules and enforced pursuant to them. Once created, the new pricing methodology would replace the pre-existing pricing methodology enforced by ad hoc regulations.

The transmission pricing principles reflect a range of objectives such as 'user-pays' principles, locational incentives and minimising distortions. All are geared towards promoting efficiency, with some also acknowledging practical considerations such as reducing transaction costs, consistency and certainty.[23] Transpower is required to develop a TPM that ensures the full economic costs of its services, including capital, maintenance, operating and overhead costs, are allocated in accordance with the transmission pricing principles contained within the EGRs.[24] When developing the TPM, Transpower is also required to follow any guidelines that the Board has published pursuant to Rule 6.2 of Section IV of Part F.

The Board published transmission pricing guidelines initially on 22 December 2004 and subsequently amended and republished them on 24 December 2004. On 18 February 2005, the Board also published a document entitled *The Commission's Statement of Reasons in relation to the Proposed Guidelines for Transpower's Pricing Methodology*, although this was not required by the EGRs. Subsequently, Contact Energy Ltd (Contact) and Meridian Energy Ltd (Meridian) sought a judicial review of the process followed by the Commission when developing the guidelines. This action was successful and the guidelines were set aside on 29 August 2005.[25] The Board then developed a new set of transmission pricing guidelines and notified Transpower of these new guidelines on 24 March 2006.[26] The TPM must be approved by the Board following the process specified in Section IV of Part F of the Rules.

The current TPM took effect on 1 April 2008. This document sets out the manner in which Transpower recovers its annual regulated revenue requirement – as determined in accordance with the relevant provisions of the *Commerce Act 1986* and, until 30 June 2011, the *Commerce Act (Transpower Thresholds) Notice 2008* – from its customers. In detailing the pricing framework that has been developed within the TPM in an effort to best meet the transmission pricing principles, it is convenient to distinguish between the arrangements that are applied to *existing* or *sunk assets* and those applied to *investments in new assets.* We examine each in turn below, and conclude by contrasting the arrangements by which charges are set for embedded generators.

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23 The transmission pricing principles that underpin the TPM are reproduced in Appendix A.

24 See: EGRs, Part F Section IV.

25 *Contact Energy Limited and Meridian Energy Limited v Electricity Commission* (CIV 2005 485-624, 29 August 2005, McKenzie J).

26 Letter from Roy Hemmingway (Electricity Commission Chair) to Ralph Craven (Transpower CEO), 24 March 2006.

3.1. Existing Sunk Assets

The majority of Transpower's regulated revenue – and hence most of what needs to be recovered through its prices – comprises a return on existing, sunk network assets. 'Ramsey' pricing principles suggest that sunk costs should be recovered through the imposition of a two-part tariff, with a variable charge to recover incremental costs associated with usage[27] and a fixed charge that does not exceed a customer's willingness to pay for the commodity.[28] Of course, it is often difficult to establish the willingness to pay of consumers, and such a principle may not be capable of implementation in a cost-effective way. In practice, therefore, simplifying mechanisms are often put in place that approximate consumers' willingness to pay.

For example, a customer's willingness to pay for a connection asset (described further below) is likely to reflect the extent to which it ***benefits*** from the connection, which in turn may be a function of how much the customer ***uses*** the connection. In consequence, charges based on usage (eg, \$/MWh consumed or injected), or peak charges based on peak demand or injections (eg, \$/MW) may be used to approximate willingness to pay. Charging consumers on such bases can deliver efficiency benefits by providing a direct indication to consumers of the costs associated with their use of those goods or services. Conversely, charges that bear no resemblance to the quantity of a good or service consumed can result in allocative inefficiencies.

However, user-pays principles must also be designed so as to minimise distortions to day-to-day production and consumption decisions, and with longer-term investment decisions.[29] These considerations are reflected to varying degrees in the charging approaches adopted for all types of existing transmission network assets. The TPM distinguishes between the revenue required to recover the costs of providing AC[30] transmission services (AC revenue) and HVDC assets during each pricing year. AC revenue is recovered via a 'connection charge' and an 'interconnection charge', whereas HVDC revenue is recovered through an 'HVDC charge'. We provide a high-level description of each of these charges below.

3.1.1. Connection Charges

Transmission connection charges recover the costs associated with connecting generators or off-take customers to the transmission system. New Zealand has a 'deep' connection charging regime. Specifically, under the present TPM, a connection asset is any asset at a defined connection node and any asset at a defined interconnection node that is specifically required to connect a customer to the transmission grid, plus any connection link that has a connection node at one or more of its ends.

As a 'rule of thumb', connection assets are those that would not exist were it not for the existence of identifiable customers, ie, if those customers were not there, then the assets

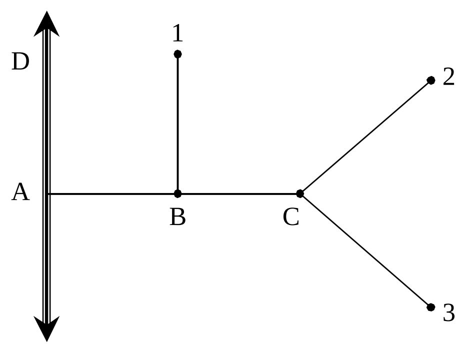
27 This already occurs through the pricing of constraints and losses in the energy market.

28 See, Frank. P. Ramsey, 'A Contribution to the Theory of Taxation,' *Economic Journal* (1927), XXXVII: p47-61.

29 In particular, such principles must be balanced against the equally important concept of *competitive neutrality*, see further discussion in 4.3.1.

30 An AC asset is a grid asset other than an HVDC asset (so includes the interconnected network and connection assets)

would also not be there. In other words, if the beneficiaries of particular assets cannot be identified (eg, if there is a 'completed loop' and therefore loop flows and parallel flows are possible) then the asset is unlikely to be a connection asset (the limited exception being 'small regional loops'[31]). Connection assets can be divided into 'dedicated connection assets' and 'shared connection assets'. The delineation between the two is illustrated using the simple grid configuration presented below:



Suppose that there are three customers located at nodes 1, 2 and 3. The 'dedicated connection assets' under the TPM would be those that can be attributed directly to the three individual customers, namely:

§ the assets comprising B ð 1, which can be attributed to customer 1;

§ the assets comprising C ð 2, which can be attributed to customer 2; and

§ the assets comprising C ð 3, which can be attributed to customer 3;

The TPM would define as 'shared connection assets' those that cannot be attributed directly to individual customers, but can be attributed to ***multiple*** customers, namely:

§ the assets comprising B ð C, which can be attributed to customers 2 and 3; and

§ the assets comprising A ð B, which can be attributed to customers 1, 2 and 3.

This 'geographic' approach can be contrasted with an 'electrical' approach, in which the definition of nodes and links is based solely on the electrical configuration, and results in comparatively fewer grid assets being defined as connection assets.[32] In this sense, the current definition of connection assets is as 'deep as possible' in that it allocates the costs associated with transmission assets to the greatest extent possible to individual customers and allows 'user/beneficiary pays' principles to be employed to the extent they are practicable, rather than 'smearing' costs across multiple grid users. This is consistent with the Guidelines for the TPM prepared by the Electricity Commission in 2006, which stated that:[33]

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[31] Small regional loops are connected to the remainder of the grid assets by a single link, which means that users of that single link (in which power may flow in any direction) and the small regional loop can be readily identified.

[32] Transpower, *Transmission Pricing Methodology Supplementary Material,* June 2006, p8.

[33] Electricity Commission, *Guidelines for Transpower Transmission Pricing Methodology,* 24 March 2006.

> ‘(9) A definition of deep connection should be developed and applied consistently and transparently. The definition of deep connection must avoid subsidisation of interconnection assets to the extent practicable.
>
> (10) The costs of connection assets are to be recovered from those connected to them.
>
> (11) Where parties share the use of connection assets then the costs should be allocated among them on a peak demand or injection basis, in a manner that maximises efficiency.’

In arriving at these Guidelines, the Electricity Commission noted that a deep connection definition would impose higher costs on users of connection assets than a more ‘shallow approach’. Moreover, it acknowledged that a shallow definition (in which connection costs comprise costs only for assets installed at the point of connection) may be easier to conceptualise and provide for more stable and predictable charges (including because the number of connecting parties using ‘shared’ deep connection assets may change over time – see section 4.3.1). However, it considered that a deep definition was to be preferred, since the practical advantages of shallow connection were likely to be outweighed by the efficiency gains thought to be offered by deep connection, specifically:[34]

> ‘[I]t seeks to attribute the cost of the connection service to parties that use the service, or cause the need for the service, regardless of the type of asset used … [and it] encourages connecting parties to make efficient location decisions for their plant, by trading off the additional costs of locating at various points with the additional costs of connection.’

Figure 3.1 below illustrates the current delineation throughout the core and non-core grid between connection and interconnection assets. The existing ‘deep connection’ nodes/links are highlighted in green. Under a shallow connection charging regime, these assets would be reclassified as interconnection assets and, assuming the TPM remained otherwise unchanged, would be recovered from load through the interconnection charge. We have been informed by Transpower that, on the basis of its 2009 revenue requirement, a switch from deep to shallow connection would involve recovering approximately an additional $21m per annum in interconnection revenue (and $21m less in connection revenue), or around 4 per cent of total HVAC revenue (which was $540m in 2009). In other words, a switch from deep to shallow connection would not involve a ***substantial*** shift in the incidence of the HVAC revenue requirement between connection charges and interconnection charges.

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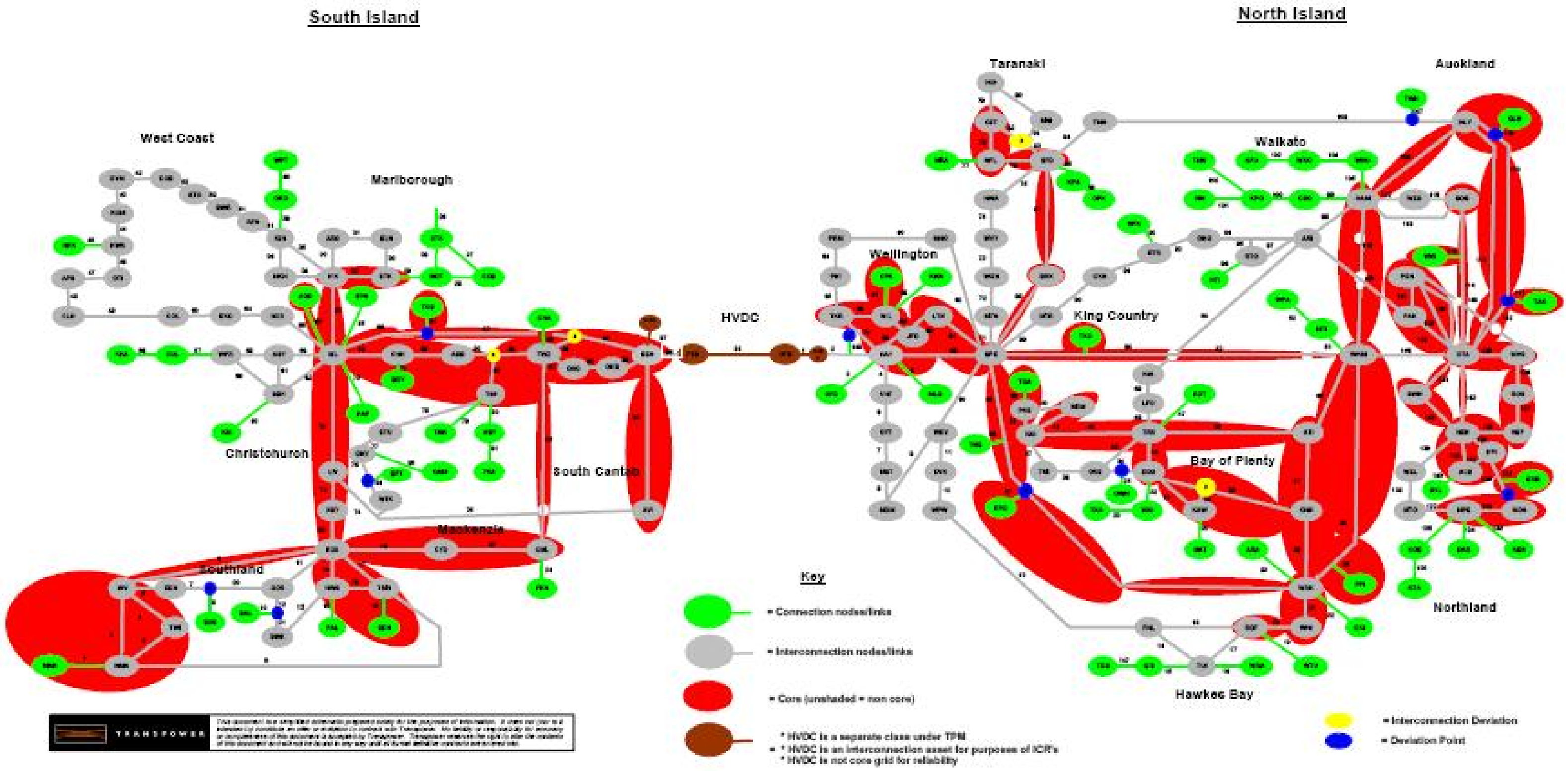
[34] Electricity Commission, *The Commission’s Statement of Reasons in relation to the Proposed Guidelines for Transpower’s Pricing Methodology*, 18 February 2005, paras 98 and 99.

Figure 3.1
Connection and Interconnection Assets



Presently, the approximately $123m in connection charges for existing connection assets[35] is recovered from customers that off-take or inject power into the interconnected grid, ie, generators, distributors and directly-connected large consumers. Charges are calculated as follows:

§ connection costs are calculated based on a return on assets, maintenance costs (for substations and lines), operating costs of switches and injection overhead; and

§ those costs are then allocated to connection locations based on the replacement cost (RC) of the connection assets, RC of substation assets, length of lines, number of switches and the RC of injection connection assets.

If there is only one customer in a connection location (ie, if the assets are 'dedicated' connection assets), then the costs attributable to that location will be primarily funded by that customer.[36] However, if there are multiple connecting customers at a connection location (ie, if the assets are 'shared' connection assets), then the costs are allocated to those customers based on their anytime maximum demand (AMD) or injection (AMI). To illustrate, suppose that the A ð B link necessitated the recovery of $5m in annual connection revenues. Suppose also that customers 1 and 2 are injection customers with an AMI of 30MW and customer 3 is an off-take customer with an AMD of 60MW. Connection charges for the A ð B link would be calculated as follows:

§ for customers 1 and 2: $5m x 25 per cent (ie, 30 ÷ [30 + 30 + 60]) = $1.25m; and

§ for customer 3: $5m x 50 per cent (ie, 60 ÷ [30 + 30 + 60]) = $2.5m.

The rationale for the peak off-take/injection pro-ration is that it reflects broadly customers' willingness to pay, consistent with economic efficient pricing principles ('Ramsey pricing').

3.1.2. Interconnection Charges

Interconnection assets are those comprising those nodes and links forming completed 'loops' (with the exception of small regional loops) such that it is *not* possible to identify individual customers (or beneficiaries) of that infrastructure. Returning to our earlier simple grid configuration, if a new link was constructed between D ð 1, then A ð Bð 1 ð D would no longer be considered a connection asset, since it would now comprise a 'loop'. In consequence, it would be considered an interconnection asset, and the attendant costs would be recovered through interconnection charges.

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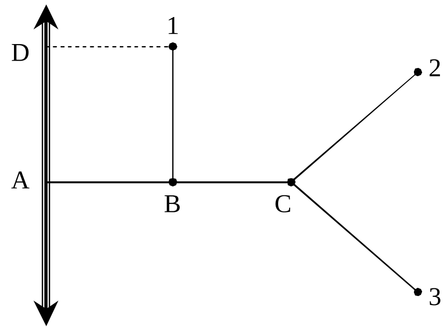
35 Note that the charging arrangements for *new connections* are slightly different since they are governed partially by the terms and conditions of 'new investment contracts', as explained further below.

36 There is an element of cost sharing because of the way the asset component of the connection charge is calculated and allocated to individual customers using replacement cost rather than actual book value. This method results in little change to charges when connection assets are replaced (which customers tend to prefer) but means that those with newer assets pay less than they would if charges were allocated using depreciated historical cost and those with older assets pay more.



The interconnection charge is a ***residual*** charge. The portion of AC revenue to be recovered by interconnection charges (interconnection revenue) is calculated as the difference between the required AC revenue and the amount recoverable through connection charges for that pricing year. Put simply, it is the 'socialised' portion of transmission costs that are not recovered through the connection charge from connecting parties (described above) or from South Island generators by means of the HVDC charge (described below). Interconnection charges are recovered from off-take customers (distributors and directly-connected large consumers) in respect of each connection location at which they have assets connected to the grid, but *not generators*.

At present, some $386m in interconnection charges is recovered from off-take customers on the following basis:

- the interconnection rate (or 'price') per kW used to determine off-take customers' annual interconnection charges is the same for all customers in all locations and is calculated by dividing the required interconnection revenue by the sum of the average of the regional coincident peak demands (RCPDs) for all customers;
- for the purpose of calculating RCPDs, the country is divided into four regions – the upper and lower North Island (UNI/LNI), and the upper and lower South Island (USI/LSI), with a different approach adopted across regions, specifically:
  - in calculating the average RCPD in the UNI and USI regions, 12 peak demand periods are used; and
  - in calculating the average RCPD in the LNI and LSI regions, 100 peak demand periods (N=100) are used;
- interconnection charges *for each customer* are then calculated by multiplying the uniform interconnection rate (price) by each customer's average off-takes at times of RCPD, ie, during the 12 periods in the UNI/USI, and during the 100 periods in the LNI/LSI; and
- the share of interconnection revenue recovered from a customer (ie, the quantum of interconnection charges paid) is therefore determined on the basis of its contribution to the average of the RCPDs.

Because the average RCPD is calculated over 12 peak demand periods in the UNI and USI regions this provides off-take customers with an incentive to shift load to non-peak times so as to minimise their annual interconnection charge. Indeed, if an off-take customer does not reduce its contribution to the 12 peak demand periods, and other customers do, then it will pay a larger annual interconnection charge. In contrast, in the LNI and LSI regions in which the average RCPD is measured over 100 peak demand periods, there is not an equivalent incentive to reduce load, because it is not likely to be feasible to control 100 peaks.

In other words, the current interconnection charging arrangements reflect a trade-off between recovering the costs associated with the sunk shared grid infrastructure, whilst minimising distortions to consumption in the LNI/LSI regions, and providing an incentive to off-take customers in the UNI/USI regions – which are areas that will soon require substantial new transmission investment – to reduce demand during peak times to improve the efficiency of usage decisions in the longer-term. The fundamental distinction between interconnection charges and connection charges is that the former are financed by identifiable customers, whereas the latter are socialised amongst ***all*** off-take customers since individual beneficiaries or users cannot be identified.

3.1.3. HVDC Charges

The purpose of the HVDC charge is to recover the cost of the HVDC Link. The HVDC Link is a high voltage link that connects the power systems of New Zealand's North and South Islands. Since the establishment of Transpower on 1 July 1994, there have been a number changes to the way in which the costs associated with this link have been recovered from transmission grid users. Initially it was decided that the costs associated with the HVDC Link would be recovered from North Island load and South Island injection customers (predominantly hydro-based generators) on a 'beneficiary pays' basis:[37]

> 'The first category is to be charged to North Island customers, since one of the benefits of the HVDC link is to reduce the cost of energy to the consumers in the North Island. Another benefit of the HVDC link is the removal of the constraint that, under normal circumstances, would increase the value of the energy produced by South Island generators.'

Initially, HVDC charges were allocated between North Island load and South Island generators on the basis of a 53:47 per cent split, respectively. The charge comprising the 53 per cent share allocated to North Island load represented the costs of providing the 'old' 600MW link, while the 47 per cent share allocated to South Island generation was based on the estimated costs of expanding the HVDC link.

Subsequently, in October 1996, Transpower published changes to its transmission pricing arrangements. Most significant of the changes was a reallocation of the costs associated with the HVDC link such that South Island generators became ***fully responsible*** for all HVDC costs.[38] A chief consideration underpinning the change appears to have been the belief that 'the bulk of the benefit of the HVDC link accrues to South Island generators',[39] since the link transported energy predominantly for the South Island to the North Island. However, we understand that other considerations included (rightly or wrongly):

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[37] See: Transpower New Zealand Limited, ***Transmission Pricing 1993***, p17.

[38] Transpower New Zealand Limited (1996), ***Pricing for Transmission Services: Introduction to the Pricing Methodology to be Applied from 1 October 1996 - Second Edition***, An information booklet from The Transmission Services Group, p11.

[39] Ibid, p8.

§ because South Island generators would not be in a position to avoid paying this charge, levying the charge solely on those customers was thought to be a non-distortionary means of cost recovery;

§ since the variable costs of South Island generators (predominantly hydro) are small, the contention was that transmission charges would not distort wholesale market bidding by, say, significantly disrupting the merit order of dispatch; and

§ charging other beneficiaries such as North Island load, would amount to charging load for a sunk cost, which may reduce consumption below the social optimal.

Under the current TPM, applicable from 1 April 2008, HVDC charges continue to be levied only on South Island generators. At present, approximately $80m in HVDC charges is recovered from South Island generators, with individual generator's charges calculated on the following basis:

§ an HVDC rate (the 'price') in $/kW is calculated for each pricing year by dividing the total required HVDC revenue by the sum of the historical anytime maximum injection (HAMI) for the relevant pricing year for all HVDC customers at all South Island connection locations;[40]

§ the HAMI at each connection location for a year is the highest of:

  – the average of the twelve highest injections at that location for the pricing year; or

  – the average of the twelve highest injections at that location during any of the four preceding pricing years.

§ the annual HVDC charge for each individual South Island customer at each connection location is then calculated by multiplying the HVDC rate by a particular customer's HAMI at that location – monthly HVDC charges are then simply one twelfth of this annual charge; and

§ finally, the loss and constraint rentals from the HVDC link are refunded to the South Island generators in accordance in proportion to their contribution to the HVDC charge.

The current HVDC rate for the 2009/10 pricing year is $23.39/kW, which recovers the total HVDC charge of $78.33m. Virtually all of the relevant costs are recovered from the three largest South Island generators, namely, Meridian Energy (Meridian), Contact Energy (Contact) and TrustPower. The simple example set out in Box 3.1 below illustrates the way in which South Island generator's annual HVDC charges are calculated.

[40] An alternative method to allocate costs based on nameplate capacity was thought to be distortionary for embedded generators, whom would be strongly disincentivised to make small injections into the grid. Transpower also considered Anytime Maximum Injection (AMI) but stated that the use of HAMI better approximates the maximum injection capacity of grid-connected generators.

Box 3.1
Derivation of HVDC Charge

Suppose that a generator is serving a single connection location in the South Island with a 60MW peaking plant, ie, it has no other generation assets at any other locations in the South Island. Suppose also that:

- HVDC revenue is $80m;
- the sum of the HAMI for the relevant pricing year for *all HVDC customers* at all South Island connection locations is 3,500MW; and
- the twelve highest injections at that location for the pricing year were all 50MW, such that its HAMI was 50MW, ie, [50 x 12] ÷ 12.[41]

In this example:

- the HVDC rate is $22.86/kW, ie, $80m ÷ 3500MW; and
- the generator's HVDC charge is $1.143m, ie, $22.86/kW x 50MW (50,000kW).

In 2005, Transpower submitted an investment proposal to the Electricity Commission for an upgrade of part of the HVDC link system. The proposal involves the replacement of 'Pole 1', and involves costs of $672 million.[42] It is expected that the upgrade will significantly increase the current HVDC charges.[43] Like existing HVDC assets, the costs associated with the upgrade to the HVDC link are scheduled to be recovered solely from South Island generators, through the current TPM outlined above.

3.2. Investments in New Assets

Hitherto we have examined only those charging arrangements within the TPM designed to recover the costs associated with existing sunk assets. However, as new assets are added to the transmission grid, the need arises to recover the costs associated with those augmentations – either from 'beneficiaries' or 'causers', or from all grid users in some manner. The two mechanisms that complement the TPM in this respect are the GIT and new investment contracts (NICs) for new connection assets. However, there is also scope for customers to undertake their own transmission upgrades. The TPM also includes arrangements by which Transpower can procure transmission alternatives and discourage uneconomic bypass of existing grid assets by means of 'prudent discounts'.

3.2.1. The Grid Investment Test

The GIT is a regulatory investment test contained within Section III of the *Electricity Governance Rules*. The GIT comprises two 'limbs'; specifically, a proposed investment will be approved if:

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41 Assume also that this exceeded the average of the twelve highest injections at that location during any of the four preceding pricing years.

42 Electricity Commission (2008), *Final Decision - Transpower's HVDC Investment Proposal*.

43 We understand that the upgrade will approximately double the existing HVDC charges, which would imply annual HVDC charges in the vicinity of $150m to 160m, based on current levels.

- it is necessary to meet applicable grid reliability standards and it maximises the expected net benefit compared with alternative projects, with the proviso that the expected net benefit may be negative, and passes sensitivity analysis (the 'reliability limb'); and
- it maximises the expected net market benefit compared with alternative projects, the expected net benefit is positive, and passes sensitivity analysis (the 'economic limb').

The reliability limb applies only to the 'core grid' (which is defined separately from the 'interconnected network' and is substantially more limited in extent), to which an 'N-1' deterministic reliability standard applies. Any other proposed investment in the transmission grid is assessed under the economic limb of the GIT, namely:

- investments in the core grid that are not necessary to meet the N-1 safety net; and
- all investments outside the core grid, where a probabilistic reliability standard applies, including the HVDC link.[44]

Ostensibly, proposed investments do *not* include any investments to be funded by means of a NIC, ie, new connection assets financed by connecting off-take or injection customers. However, for the reasons we describe below, despite this exclusion, the effect of clause 40.2 of the Benchmark Agreement is that such investments are also, strictly speaking, supposed to meet a test equivalent to the economic limb of the GIT before proceeding.

The alternative projects against which the proposed investment is compared in undertaking the GIT include:

- any alternatives to investment in the grid including investment in local generation, energy efficiency, demand side management, and distribution network augmentation; or
- transmission alternatives to the proposed investments including non-trivial variations in the timing of proposed investments.

The net benefits and costs are estimated for various future market development scenarios for the proposed investment and alternatives. Market development scenarios are expected to be the same in definition, and number, as those set out in the Statement of Opportunities (SOO) produced by the Board (unless others proposed by Transpower are considered more appropriate).[45] If the expected NPV of the proposed investment exceeds the expected NPV of alternative investments across those market development scenarios, then it will pass the GIT (provided that NPV is greater than zero for 'economic' investments).[46] In practice, the scale of application of the GIT depends upon the amount of capital expenditure involved.[47]

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44 See for example the HVDC grid upgrade plan relating to the HVDC Pole 1 replacement investigation project.

45 Market development scenarios are expected to be the same in definition, and number, as those set out in the Statement of Opportunities (SoO) produced by the Electricity Commission (unless others proposed by Transpower are considered more appropriate). The last SoO was published by the Commission in August 2008 with five scenarios, each with equal probability of occurring. The scenarios included assumptions about future investment in transmission and the HVDC cable. The five scenarios are: 1) 'sustainable path'; 2) 'South Island surplus'; 3) 'medium renewables'; 4) 'demand-side participation'; and 5) 'high gas discovery'.

46 Specifically, estimates are compared with a 'base case', where the base case is the 'reasonable future state of the electricity industry without the proposed investment or alternative project'. These comparisons are weighted against

The costs associated with investments that have passed the GIT subsequently are recovered by Transpower under the TPM, in the manner described in the previous section. For example, new investments in interconnection assets are recovered from off-take customers, and new investments in HVDC assets are recovered from South Island injection customers.

3.2.2. New Connection Assets

In principle, investments in new connection assets allow greater scope for the recovery of relevant costs from beneficiaries or 'causers', which can generally be expected to promote more appropriate investment decisions. This philosophy is reflected in the NIC approach to financing investments in new connection assets. NICs are agreed to between Transpower and a transmission customer in relation to connection infrastructure, eg, a new generator wishing to connect to the interconnected grid may request Transpower to build the necessary infrastructure. Such contracts are designed to recover the cost of an investment in excess of $20,000 following the specific request from a customer.[48] Pricing is based on the actual project cost, plus a return on the asset.

An NIC is therefore essentially a capital funding contract, whereby the capital component of the investment is carved out of the TPM and dealt with via a contract between the customer and Transpower. All other connection costs – most notably operating and maintenance costs – continue to be provided for under the TPM (although, if they are 'dedicated' connection assets it makes little difference, since the one customer will pay all of the relevant connection charges, whether under the NIC or the TPM[49]). However, the charging arrangements begin to get more complicated when 'second- and third-movers' seek to obtain access to new connection assets that have been fully or partially funded by first-movers under a NIC.

Consider the simple grid configuration below. Suppose that customer 1 wishes to connect to the interconnected network at grid exit point 'A', and that this requires the construction of a long spur line. The capital component of this investment would be funded under a NIC, and the remaining connection costs would be attributed to customer 1 under the TPM. Subsequently, customers 2 and 3 also wish to connect to the interconnected network, using a

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the market development scenarios. In other words, there are three steps in estimating the applicable net benefits or costs when applying the GIT:

- determine market development scenarios with corresponding probabilities;
- estimate the net market benefit or cost of each proposed investment or alternative investment under each scenario, including the base case; and
- calculate the probability weighted average of net market benefit for each proposed investment or alternative investment across the scenarios.

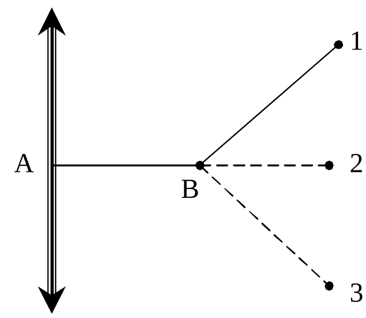
Each net benefit or cost is therefore a probability weighted average. The probabilities assigned to each of the market development scenarios are used to weight the net market benefits or costs, ie, they are expected net present values (NPVs). The expected NPV of the proposed investment is compared to the alternative investments to determine whether the GIT is passed.

47 Smaller projects, eg, the Maungatapere Bus Security ($4 million) and West Coast GUP investment proposals, only consider a small number of scenarios, with minimal sensitivity analysis. However, larger projects, such as the Woodville-Mangamaire-Masterton upgrade compare more scenarios, with more extensive sensitivity analysis.

48 Investments less than $20,000 can be covered by Minor Works contracts, in which pricing is based on the actual project cost and is invoiced on project completion as a single one-off charge.

49 With the proviso that there is an element of sharing of asset-related costs under the TPM (see footnote 15).

significant proportion of the connection infrastructure funded by customer 1. The assets comprising B ð 2 and B ð 3 can be attributed to customers 2 and 3, respectively and dealt with under separate individual NICs. However, how is the link between A ð B treated?



The 'non-capital' costs associated with A ð B would be allocated between customers 1, 2 and 3 on the basis of their AMI or AMD as per the methodology contained in the TPM described above. However, hitherto the capital costs associated with the A ð B link have been financed solely by customer 1, under the terms of its NIC with Transpower. Following the entry of customers 2 and 3, the capital recovery mechanisms contained within that initial NIC with customer 1 need to be revisited. Presently, the standard approach is to adjust that initial NIC, and structure the NICs with customers 2 and 3, to reflect the capital allocation mechanism *contained in the TPM.*

Specifically, the annual capital costs attributable to customers 1, 2 and 3 (which would be based on estimates of the depreciated historical cost of the A ð B connection asset) would be allocated based on their AMD or AMI, in an equivalent manner to non-capital costs. Of course, if customer 1 has been in the location for an extended period of time, this gives rise to the issue of whether customers 2 and 3 should be required to compensate that customer for the time spent solely financing what is now a shared connection asset. However, there are presently no formal regulatory arrangements in place to address such issues – it is left to the individual parties to come to private arrangements acceptable to themselves and Transpower.

Finally, there is the question of the extent to which customer-funded investments in new connection assets are subject to economic testing. As noted above, investments funded by means of a NIC *ostensibly* are excluded from the application of the GIT. However, clause 40.2 of the Benchmark Agreement between Transpower and all designated transmission customers that governs transmission charging arrangements between the parties effectively *circumvents* this exclusion.[50] The clause requires all customer-funded investments[51] to satisfy the applicable grid reliability standards. Strictly speaking, this means that investments in new connection assets *should* comply with the 'economic' limb of the GIT, since:

§ investments in new connection assets will almost always be located in the non-core grid where the N-1 deterministic reliability standard does not apply; and

50 See: Schedule F2 of Section II of Part F of the EGRs.

51 Which will in virtually all cases be investments in new connection assets.

- § the applicable reliability standard for the non-core grid is the level that would be achieved if *all economic investments* were to be implemented.

In consequence, in order for a new connection investment to comply with the applicable grid reliability standards – and so clause 40.2 of the Benchmark Agreement – it must be an economic investment, under the economic limb of the GIT. On the face of it, the literal consequence of clause 40.2 is that every connection investment – no matter how small – should be subjected to a GIT process. However, we understand that ***in practice***, where both the connecting party and Transpower are in agreement that the investment should be made, the economic benefits are 'taken as read' and a comprehensive cost-benefit analysis is ***not*** undertaken, since it is considered unnecessary.

3.2.3. Proprietary Transmission Investment

There are two alternatives to entering into a new investment contract with Transpower in order to procure a connection asset. The first is for a customer to build the asset itself instead of Transpower. For example, a generator that required, say, a 50km spur line to connect its power station to a grid injection point could obtain the relevant resource consents and construct the line itself. In these circumstances it would own the asset, since it would effectively be considered to be part of its power station. Connection charges would be limited to those incurred at the relevant grid injection/exit point, including for equipment such and switches and for injection overheads.

In other words, the transmission line would not be 'open access', which sets it apart from an equivalent asset built by Transpower and funded by means of a NIC. Unlike the preceding NIC example, second- and third-movers wishing to obtain access to the line owned by the proprietor generator would not have an automatic right of access at a price determined by the TPM. Rather, they would need to negotiate directly with that generator, whom in practice is likely to have relatively little (if any) incentive to provide such access.

An alternative to building the link itself is for the generator to enter into a contract with the local distribution company, whereby the distributor would build the asset. The potential advantage of the distributor constructing the asset is that it can take advantage of its compulsory acquisition powers. Depending on the way in which the contract is struck, the generator may retain a similar degree of control to the situation in which it built the asset itself. In particular, the resulting transmission line may ***not*** be an open access line, and restrictions on second- and third-movers connecting may exist. The resulting connection charges would be equivalent to the circumstances in which the generator built the asset itself.

For the reasons outlined above, a literal interpretation of clause 40.2 of the Benchmark Agreement ostensibly suggests that even private transmission construction projects must be economic investments. In other words, even those investments that are not undertaken by Transpower should, strictly speaking, be subjected to an economic test equivalent to the GIT. However, as noted earlier, in practice it is unlikely that rigorous economic testing of such projects will occur, or that it is necessary.

3.2.4. Transmission Alternatives

Not all of the Transpower's investments must be in ***transmission*** assets. The EGRs also provide it with the right to provide or procure transmission *alternatives*, such as investments in local generation, energy efficiency initiatives, demand-side management and distribution network augmentation. Such services may substitute for connection assets, interconnection assets or both.[52] Where a transmission alternative substitutes for a service that would otherwise be provided by:

- connection assets, the costs of the alternative are allocated between all customers at the relevant connection locations in the same proportion as those customers' existing charges;
- interconnection assets, the costs of the alternative are allocated between off-take customers in the same proportion as those customers' existing charges; and
- both connection assets and interconnection assets, the allocation of costs between connection and interconnection assets is made by reference to the customer allocation methodology contained in the TPM.[53]

Under the TPM the costs of funding transmission alternatives are charged to, and payable by, customers in the month following that in which Transpower is invoiced for those costs. If such alternatives become more commonplace, these funding arrangements may therefore lead to some volatility in connection and interconnection charges. However, to date, no proponent has put up a substantive transmission alternative to Transpower so it is too soon to come to a view on the appropriateness of the arrangements.

3.2.5. Prudent Discount Policy

The purpose of the prudent discount policy is to help ensure that the TPM does not provide incentives for the uneconomic bypass of existing grid assets. Specifically, the policy aims to deter investment by Transpower customers in projects that would allow them to reduce their own transmission charges while increasing "the total economic costs to the nation as a whole". Two conditions must hold before a customer may obtain a prudent discount:[54]

- the customer's project must be technically, operationally and commercially viable and have a reasonable prospect of being able to be successfully implemented; and
- the project must be uneconomic to implement given Transpower's economic costs of providing existing grid assets and the economic costs that would be incurred by the customer if it proceeded with the alternative approach.

If a customer considers that a project meets these criteria it can submit a proposal to Transpower, which must then assess it to determine whether or not (amongst other things):

- it is technically and operationally feasible;

[52] See: Schedule F5 of Section IV of Part F of the EGRs, p229.

[53] See: Schedule F5 of Section IV of Part F of the EGRs, p220.

[54] See: Schedule F5 of Section IV of Part F of the EGRs, p231.

§ it could reasonably be expected to reduce the customer's transmission charges; and

§ it is uneconomic, the assessment of which involves Transpower calculating:

1. the net present value (NPV) of the estimated total costs of the alternative project proposed by the customer;
2. the NPV of continuing to provide transmission services to the customer if the alternative project does not proceed;
3. the NPV of continuing to provide transmission services to the customer if the alternative project does proceed; and
4. if the amount calculated in step 1 less the amount calculated in step 2 exceeds the amount calculated in step 3, the alternative project will be determined to be economic and no discount will be provided (and vice versa).

If a customer's alternative project meets the criteria above, Transpower will offer a prudent discount agreement designed to place the customer in the position which it would have been had it undertaken the project, without it actually implementing the proposal. Specifically, a prudent discount agreement provides the customer to pay to Transpower an annuity determined by reference to the customer's cost of funding, maintaining and operating the 'notional' project over the course of the agreement, applying a commercial discount rate. Transpower will then calculate the customer's transmission charges in accordance with the TPM *as if* the project had been implemented.

The types of situations in which a prudent discount might apply are:

§ embedding of existing generation, ie, where a customer could build transmission assets to embed an existing grid-connected generator in order to be able to net that generation off its demand and reduce that customer's interconnection charge – the prudent discount would be a calculation of the customer's interconnection charge as if the generation were embedded in the load; and

§ transmission duplication, ie, where a customer proposes to build its own transmission or distribution assets that would duplicate some of Transpower's existing assets – the prudent discount would be a variation to the customer's connection charges to reflect the cost of the customer's alternative investment over the period of the agreement.

However, there a number of situations where a prudent discount would ***not*** apply, including proposals to construct *new* embedded generation (since doing would be considered contrary to the Government's October 2004 Policy Statement on embedded generation) and proposals to avoid customers investing in aggregate GXP loads (since the RCPD method of calculating interconnection charges in effect already aggregates demand).

3.3. Embedded Generation

The transmission charging arrangements for embedded generators differ materially from those for 'transmission-connected' generators insofar as charges apply to the owner of the grid in which the generator is embedded. Embedded generators do not pay connection charges in the same manner as transmission-connected generators because they are not connected at a connection location. Rather, the only aspects of the TPM that continue to apply are injection overhead charges and, in the South Island, HVDC charges. However, these charges apply only if there is net injection to the interconnected transmission grid, ie, if all injections from the embedded generator are accounted for by local load, TPM charges will be zero.

The embedded generator must instead enter into a connection arrangement with the distribution company. The applicable connection arrangements are contained in the *Electricity Governance (Connection of Distributed Generation) Regulations 2007* (DGRs). However, the DGRs apply only if the distributor and generator decide not to (or fail to) enter into a connection contract outside of the regulated terms provided,[55] and we understand that many connection agreements were negotiated prior to the regulations being put in place. The regulated terms are outlined in Schedules 2-4 of the DGRs, with Schedule 4 outlining the pricing principles to be applied. The pricing principles are designed so as to allow the:[56]

> '[R]ecovery of reasonable costs incurred by [the] distributor to connect the generator and to comply with connection and operation standards within the network, and must include compensation of any identifiable avoided or avoidable costs.'

The costs and avoided costs are likely to arise from the following factors:[57]

- distributed generation may increase a distributor's costs due to a need to reinforce the local network to allow for export of power or increased fault levels; or
- it may reduce costs by deferring the need to reinforce the local network by reducing demand on the system; also
- distributed generation may reduce transmission charges by reducing the network's regional coincident peak demand and by contributing to deferral of transmission upgrading.

In other words, under the DGRs embedded generators are required to compensate the distributor for its capital, maintenance and operating costs associated with the connection assets required to connect it to the distribution network. However, the distributor must also pay the embedded generator a sum reflecting the costs that it 'avoids' as a result, eg, through any consequential reduction in its average RCPD because of the generator embedding there. This may make embedding generation an attractive proposition as compared with transmission connected generation.

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55 The DGRs state that if parties agree to vary from any of the terms in Schedules 2-4 of the DGRs, the parties will be opting for an unregulated contract and that a breach of the terms of such a contract is not a breach of the DGRs.

56 DGRs, schedule 4(2).

57 The Electricity Commission (2009) *Distribution Pricing Methodology: Consultation paper on a model approach*, p45. Schedule 4 also states that estimated costs to the distributor may be adjusted ex post. Adjustments involve the calculation, and comparison, of both the actual costs incurred by the distributor as a result of the distributed generation being connected to the distribution network and the costs that would have been incurred had the generation not been connected. If these costs do not balance, then the distributor must notify and recover or refund those costs after they are incurred (unless the two parties have agreed otherwise), these costs include any capital and operating expenditure, a generator's share of generation-driven costs, if multiple generators are sharing an investment, and the repayment of previously funded investment, again when multiple generators share investments. See: *The Electricity Governance (Connection of Distributed Generation) Regulations 2007,* Clause 2, Schedule 4.

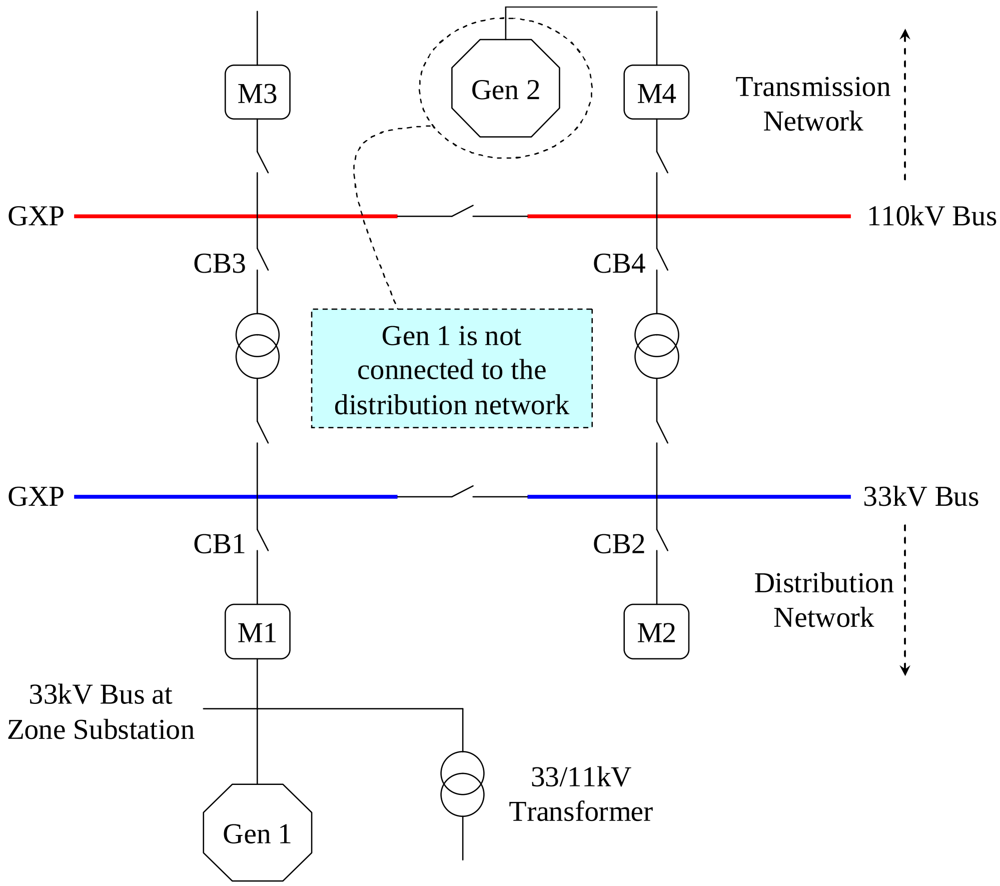
An unusual feature of the current TPM is that a generator does not necessarily have to be connected 'behind load' in order to be treated as embedded. Rather, depending upon the ownership arrangements for lines connecting generators to circuit breakers, it is possible for a generator to be considered embedded – and for the interconnection charges paid by distributors to be adjusted accordingly – even if it is connected to the *transmission* network, and makes zero injections into the distribution network. This somewhat peculiar scenario arises because of the way that assets under common ownership are aggregated by Transpower for the purpose of calculating interconnection charges.

Figure 3.1 illustrates. In this example, the quantum of interconnection charges is influenced by the identities of the parties that own the lines connecting the circuit breakers CB1 to CB4. If a distribution company owns the lines connecting to CB1 and CB2, then the sum of injection from generator 1 (Gen 1) will be deducted for the purposes of calculating the distributor's interconnection charge. This avoided charge would then need to be passed through to Gen 1, consistent with the methodology described above. Gen 2 will *not* be considered to be an embedded generator. However, if the same distributor also owns the line *connecting Gen 2 to CB4*, then the sum of injection from *Gen 1 and Gen 2* will be deducted when calculating the distributor's interconnection charge. In other words:

- if the same distribution company owns the lines connecting to CB1, CB2 and CB4, then *Gen 1 and Gen 2* will be considered to be embedded; and
- if these lines are under separate ownership, *only Gen 1* will be considered to be an embedded generator under the TPM.

The reason is that when Transpower determines the assets at the GXP, it aggregates all of the meters on both sides of the 110kV and 33kV Bus *by owner*. This creates an unusual asymmetry whereby the classification of a generator is potentially determined on the basis of whom owns the line connecting it to the GXP. The potential result is that a greater proportion of interconnection costs may be avoided by a distributor if it owns assets connecting to generators on *both sides* of the grid exit point (GXP). On one view, this is a peculiar outcome, since distributors can avoid interconnection charges (and generators can be paid such charges) by connecting lines to generators that are *not connected behind load*, but are effectively taken to be embedded generators nonetheless.

Figure 3.2
Types of Embedded Generators



Transpower's approach to aggregating meters therefore potentially results in the classification of a generator being determined on the basis of whom owns the line connecting it to the GXP. These arrangements risk creating incentives for generators and distributors to over-invest in such assets in order to avoid paying interconnection charges (or to receive payments for avoided charges, as the case may be). We understand that Transpower previously calculated interconnection charges separately for the 110kV and 33kV Bus. This would address any potential incentive problem arising from the current practice. In the above example, such an approach would result in only the injection from Gen 1 being deducted when calculating the distributor's interconnection charge, regardless of whether it owned the line connecting Gen 2 to CB4.

3.4. Summary

The way in which Transpower recovers the full economic costs associated with providing electricity transmission services, including capital, maintenance, operating and overhead costs, is contained within its TPM. The TPM recognises that new investments in connection assets are likely to be made pursuant to NICs, because of the requirements of the EGRs. The costs associated with existing assets are recovered as follows:

§ the costs associated with existing connection assets are recovered from both off-take and injection customers on the basis of their AMD and AMI, respectively;

§ the costs associated with existing interconnection assets are recovered solely from off-take customers, with the allocation based on their contribution to the average RCPD in four separate pricing regions; and

§ the costs associated with existing HVDC assets are recovered from South Island injection customers on the basis of their HAMI. Figure 3.3, which is reproduced from the TPM, provides a summary of Transpower's charges for existing network assets.

Figure 3.3
Summary of Transpower's Charges for Existing Network Assets

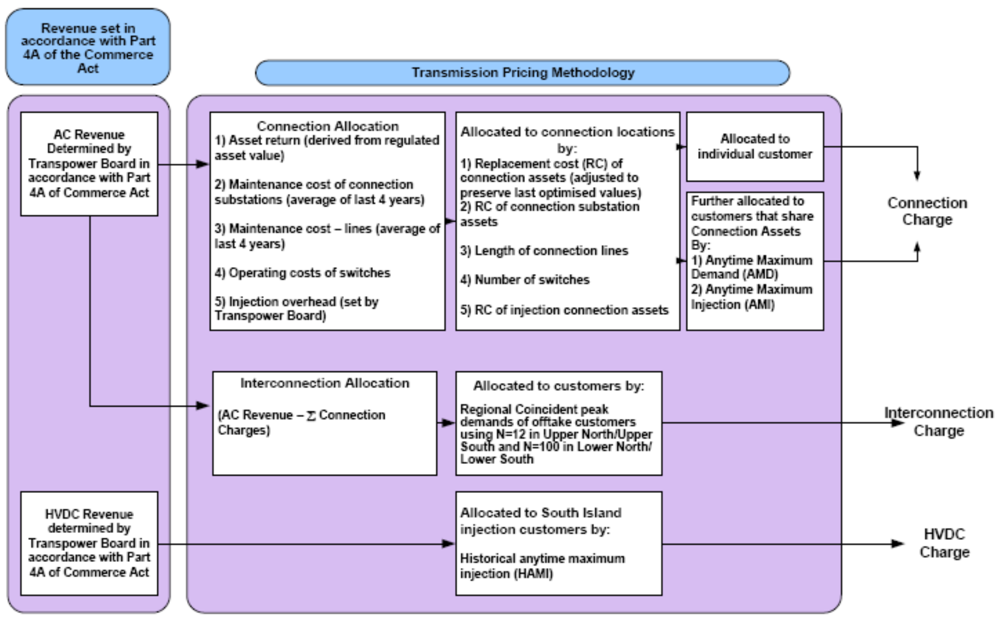
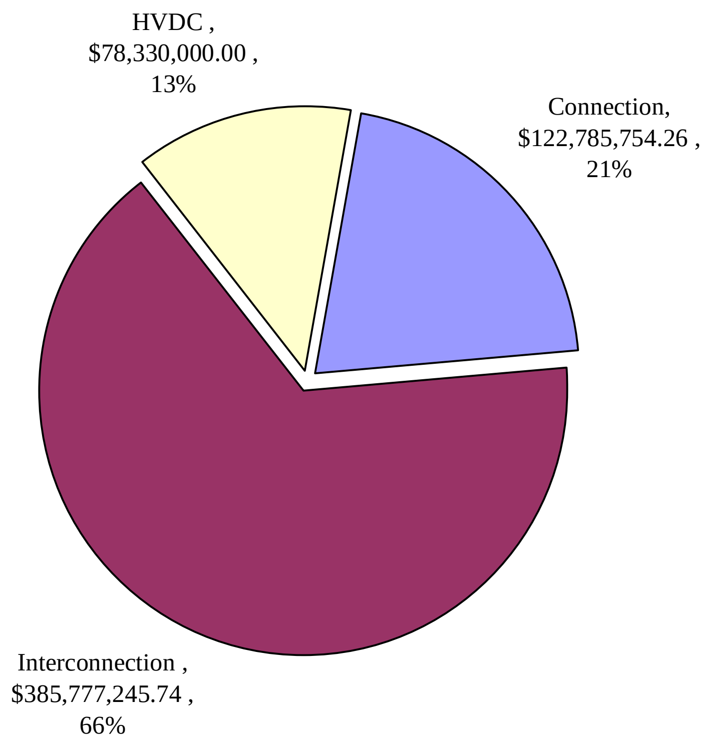


Chart 1 approximates the allocation of HVAC and HVDC charges for existing network assets. The data for connection and interconnection charges relates to the 1 April 2008 to 31 March 2009 period, whereas the HVDC charges are for the 2009/10 period (before congestion rentals).

Chart 1
Allocation of HVAC and HVDC Charges



There are two separate (but related) mechanisms by which investments in new transmission assets are recovered by Transpower, specifically:

- the costs associated with investments that have passed the GIT are recovered by Transpower ***under the TPM***, in the manner described in the previous section, eg, new investments in interconnection assets that have passed the GIT are recovered from off-take customers based on their RCPDs as applicable; and
- the capital component of a customer-funded investment in new connection assets is recovered through a *NIC*, with non-capital costs continuing to be funded under the TPM – clause 40.2 of the Benchmark Agreement ostensibly requires such investments to meet the 'economic' limb of the GIT but, as noted above, in practice a comprehensive cost-benefit analysis may not be undertaken.

Customers also have the option of constructing new connection assets themselves, or entering into contractual arrangements with parties other than Transpower, eg, distribution companies. In these instances, connection lines cease to be 'open access' and connection charges are limited to a return on dedicated customer assets at grid exit/injection points.

In the following sections we set out the key issues that appear to arise from the existing transmission pricing arrangements and identify those aspects that appear to be most conducive to successful reform when considered against the guiding criteria described in the introductory section.

4. Price Signals Provided by Existing Arrangements

Setting transmission charges so as to provide appropriate incentives for the efficient use of and investment in the transmission network is one of the most challenging problems arising in designing the regulatory arrangements to support efficient electricity markets. As section 1.1 explained, we understand that industry and major consumer stakeholders would like to see a TPM that:

- sends efficient locational signals (assuming these signals are not adequately provided elsewhere);
- sends capacity signals to, among other things, encourage efficient demand-side response;
- sends efficient signals as to the timing and nature (as well as location, identified above) of new generation development; and
- endures in line with the time frames for investment decisions so as to provide certainty as to the nature and extent of those price signals to all stakeholders.

In other words, the TPM should recover transmission costs in an enduring manner that minimises distortions to the use of the existing network while providing efficient signals for longer-term investment decisions in load, generation and demand-side management projects. In this section we consider the extent to which the existing pricing arrangements are likely to meet the criteria espoused in the problem definition. In so doing, we note that price signals are currently provided to varying degrees through:

- the operation of the nodal pricing and dynamic loss factor arrangements in the NZEM;
- the application of the GIT;
- the deep connection charging arrangements in the TPM;
- the charging arrangements for the HVDC link; and
- the interconnection charging arrangements in the TPM, which are targeted at load.

We focus in particular upon the extent to which the existing arrangements provide sufficient incentives to *locate new generation and/or load efficiently*, since the contention is sometimes made that they do not, and the need to provide efficient locational signals is a prominent feature of the problem definition.

4.1. Nodal Prices and Dynamic Loss Factors

Prospective generation investments may be driven by commercial imperatives arising from the nodal pricing arrangements. The nodal pricing and dynamic loss factor regime in the NZEM provides generators with an incentive to choose locations in the network that mitigate transmission losses and network congestion. Where there is excess generation at or near a constrained node, congestion gives rise to the risk of a generator being ‘constrained off’ at inopportune times until the constraint eases. Likewise, if a generation node is distant from load centres a generator may incur significant transmission losses. In both cases, there are corresponding detriments to its operating profitability. Put simply, a generator that locates on the 'wrong side' of a constraint or in a location with high generation loss factors is likely to be foregoing operating profit as compared with another location.[58]

Similar incentives are provided to large industrial customers, whom are liable to face higher retail electricity prices if they locate in congested locations or in locations affected by losses. However, for the reasons described in section 2.3, anticipated retail electricity prices are unlikely to be a paramount consideration for load when it comes to locational investment decisions, so it is unlikely that nodal prices – or indeed electricity prices in general – factor heavily in locational investment decisions made by load. We note also that, should the Electricity Commission's proposal for a Locational Rental Allocation (LRA) mechanism be implemented, this may reduce the variation in nodal prices faced by load across the NZEM. Indeed, the LRA proposal would effectively do away with full nodal pricing on the 'demand-side' and introduce zonal pricing, but leave full nodal pricing on the supply-side (generator) side.[59]

In other words, with full nodal pricing a generator has at least ***some*** incentive to locate new generation plant[60] in apparently 'sensible' locations, ie, those that can mitigate network constraints and/or transmission losses, as compared with an export-constrained node and/or a node that is distant from load centres. Indeed, the forecast effect on nodal prices has been a critical consideration in a number of recent generation investment decisions made in the New Zealand market, the details of which have been disclosed to us on a confidential basis. The incentives also exist for load although, for the reasons set out in section 2.3, the responsiveness of those customers to such signals is likely to be considerably more muted than for generators.

Although some appropriate signals are provided by nodal prices and losses, the question is whether those signals are sufficient in themselves to ensure efficient investment in new transmission and generation. Put another way, with full nodal pricing and a dynamic loss factor regime in place, is it necessary to provide any ***further*** price signals in an attempt to ***change*** behaviour (as opposed to setting charges so as to ***minimise*** distortions to behaviour), or do short-run nodal price differentials and losses provide adequate long-run signals? Most importantly, can we rely upon nodal prices and losses to prevent generators from building in inappropriate locations? The general consensus in the economics literature[61] is that efficient signals can be delivered, ***but only under some strict conditions that do not apply in practice.***

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58 We note that ultimate profitability will also be heavily influenced by contract prices. This is especially the case in New Zealand where generators are often vertically integrated.

59 The Electricity Commission's LRA proposal involves providing a hedge to wholesale market participants that purchase electricity in regions exposed to high spot prices relative to spot prices generally. It does this by allocating transmission rentals to purchasers based on the extent their nodal prices exceed a reference price, weighted to reflect the purchaser's load. Although spot prices are not directly altered by LRAs, the effective price paid by wholesale market purchasers reduces to the extent they receive rentals. The objective would be to increase competition in the retail electricity market by improving hedge market liquidity. Specifically, the initiative would be intended to encourage gentailers to compete for customers nationwide because LRAs would partially protect them from high local prices when local transmission constraints occur. We note that there is disagreement amongst the industry regarding the extent to which the proposed LRA mechanism would be likely to achieve its stated purpose. We have not sought to assess the LRA proposal in any detail, since it is not integral to our analysis.

See: http://www.electricitycommission.govt.nz/opdev/wholesale/Hedge/transmission-hedges/?searchterm=LRA

60 And off-take customers with respect to load, as we discuss further below.

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Specifically, as Biggar (2009) highlights, nodal pricing will yield efficient long-run generator investment signals when:[62]

- there are no economies of scale and scope in generation or transmission;
- there is effective competition between generators at all locations in the network; and
- transmission is augmented continuously so that the cost of adding one more unit of transmission capacity – the long-run marginal cost (LRMC) – is equal to the avoided cost of future constraints and losses, ie, the 'LRMC investment rule' introduced in section 2.1.

Absent economies of scale and scope, full nodal pricing, when coupled with the LRMC investment rule for efficient transmission augmentation, will deliver efficient use of and investment in the transmission network, and generation. Full nodal pricing ensures that generators continually face the SRMC of use of the transmission network, while the LRMC investment rule ensures that the transmission network is augmented to the point where the LRMC of expansion is equal to the avoided cost of constraints and losses. No further price signals are required to ensure efficient use of and investment in transmission. However, this theoretical ideal does not reflect reality.

Rather, several of the basic economic characteristics of transmission described in section 2.2 serve to limit the strength of the locational signals contained within the nodal pricing and dynamic loss factor frameworks, and can undermine the achievement of static and dynamic efficiency. The fundamental problem is that, in practice, there are numerous reasons why the average of the SRMC of transmission over time will virtually ***always be lower than the LRMC***. Fraser (2002) explains that SRMC pricing (nodal pricing) will yield price signals that are systematically below LRMC for the following reasons:[63]

- the SRMC of the use of the transmission network is signalled through differences in nodal prices – but if spot prices are capped below the true value to customers of lost load, price differences will at best send a muted signal of the true marginal cost of the transmission network;
- the business of transmission is very complicated and unpredictable, so transmission planners justifiably 'err on the side of caution' when investing in new capacity;
- transmission planners use reliability standards (eg, the N-1 deterministic standard for the core grid) that are independent of economic costs, and the same reliability standards are applied to remote customers and to centrally-located customers (this is not necessarily the case in New Zealand, since the core grid is limited in scope);
- market power problems may lead to overbuilding transmission in an attempt to promote competition generally in power markets;
- there are valid national security reasons to build too much transmission; and

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[62] D.Biggar, (2009), A Framework for Analysing Transmission Policies in the Light of Climate Change Policies, Draft, April, p14.

[63] See: H. Fraser, 'Can FERC's Standard Market Design Work in Large RTOs?', *Electricity Journal*, Volume 15, Number 6, July 2002 , p25.

§ the result of economies of scale in electricity transmission is that the transmission network is commonly overbuilt, and the amount by which overbuilding reduces SRMC below LRMC is considerable, ie, it is impossible to match transmission capacity precisely with transmission requirements at all times.

In other words, short-run marginal transmission costs (represented by nodal price differentials) will be systematically lower than long-run marginal transmission costs because new transmission will continue – for good reasons – to be built before being justified by short-run congestion and losses savings alone. Put another way, the locational price differences between 'node A' and 'node B' will almost always be lower than the long-run cost of building transmission between node A and node B. This dampens the financial incentives provided by the nodal pricing framework, because it reduces the incidence and extent of price separation between nodes.[64]

Recall that it is for these reasons that a FTR framework cannot be relied solely upon to drive transmission planning and investment. As section 2.2 explained, because of the practical complexities described above, any auction of FTRs between nodes will be highly unlikely to recover the annualised cost of financing the link. The reason that users would not be prepared to pay such a sum is that the estimated future annual nodal price differentials (losses and congestion rents) between the nodes would not reach that level – investment would take place before SRMC differentials of that quantum emerged.

Relying solely upon nodal prices and losses to provide appropriate signals for new investment can therefore provide generators with incentives to locate in the wrong areas, and consequently distort transmission investment. Specifically, absent other signals, if a generator knows that it will not be charged the extra long-run cost of the transmission investment necessary to accommodate them, and to get its electricity to the load centres, since SRMC will never increase to LRMC (eg, if the cost will be averaged across the whole industry – or on load), then such costs will not be taken into account in its locational decision, and an inefficient decision may be made. In other words, although nodal prices and losses provide ***some*** incentives for generators to locate in sensible locations, they cannot be relied upon to deliver efficient outcomes on ***all occasions.***

For this reason, a number of additional mechanisms within the existing transmission pricing arrangements augment the signals provided by nodal prices and losses. These include the application of the GIT, the deep connection charging arrangements, the charging arrangements for the HVDC link and, to a lesser extent, the interconnection charging arrangements that are targeted at load. As the following sections explain, some aspects of these arrangements are likely to provide beneficial incentives, and others seem likely to result in inefficient distortions.

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[64] This may be exacerbated by the bidding conduct of vertically integrated generators. For example, suppose that a generator at an injection node was vertically integrated with a retailer serving some or all of the load at an adjacent off-take node (as many New Zealand generators would be). It would have an incentive to ensure that any constraint between the two nodes ***never binds***. Rather, it would be likely to structure its offers so as to maximise its net exports without actually hitting the constraint and triggering a price separation between the nodes. That is, it will bid so as to ensure that it remains the 'marginal generator' to the off-take node at all times, which it can achieve by ensuring that it bids low enough in terms of both price and quantity to avoid the constraint binding in price. The reason is that if the constraint binds, its retail arm would be required to supply power purchased at the higher price at the off-take node, whereas its generation arm would only receive a lower price at the injection node.

4.2. The Application of the GIT

The GIT assessment process requires that all economic costs and benefits of a proposed investment project, and its alternatives, are taken into account in the assessment of net economic benefits. This means that the relative costs and benefits of augmenting the transmission network in one location, as opposed to undertaking alternative investments – in the transmission network, in new generation, or in other initiatives – in other locations should be taken into account. In principle then, the GIT can be thought of as ***strengthening*** the locational signals provided by nodal prices and losses, and ensuring that any constraints in the network are 'built out' in the least cost way, rather than augmentation being driven by the prior location decisions of generators. In this sense, the GIT should therefore go some way to supporting new generation investment that is efficiently located.

However, the extent to which this holds in practice is unclear. The GIT affects generators' locational signals primarily by altering the degree of congestion throughout the transmission system, and hence anticipated nodal price differentials. Of course, congestion can be a good thing for a generator, or a bad thing, depending on which side of a constraint it has located. In fact, if Transpower tends to over-build transmission for the reasons described in section 4.1, the effect is that the GIT will reduce congestion when it is uneconomic to do so, thus depriving generators in 'good' locations of the congestion component of their long-run marginal prices – and dampening their price signals to locate where they are needed most.

Moreover, although the market development scenarios that underpin the GIT can (and do) influence the investment decisions of generators,[65] ultimately, parties are still free to locate where they please. If a generator builds in a 'poor' location it may be the case that, once built (sunk), the GIT indicates that a transmission upgrade is economic, whereas had it been assessed before investment costs were sunk a different conclusion may have been reached. Whether a generator would behave in this manner – and risk being constrained off, or being hampered by high loss factors if an upgrade does not eventuate (or in the interim before an upgrade does eventually proceed) – is unclear, but if it anticipated that future transmission reviews might be favourable this scenario is certainly conceivable.

In addition, there are potential problems with the circumstances in which the GIT is applied, and the *way* in which it is undertaken. First, as 3.2.1 explained, strictly speaking, all new investments in connection assets should meet the economic limb of the GIT (although, in practice Transpower does not engage in vigorous economic testing). The relevant question for the purposes of this review is whether the GIT ***should*** be applied to new connections and, if so, how. We address this question in section 5.3.2.3 and suggest some potential alternatives.

Second, there is presently no scope for the costs associated with 'nationally significant' or otherwise beneficial investments to be socialised if such investments pass the economic limb of the GIT. In particular, there is presently no scope for the GIT to be applied in such a way that 'large connection investments' (eg, to serve a new generation location), would be

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65 The market development scenarios utilised within the GIT process have been an important consideration in several recent generation investment decisions made in the New Zealand market, the details of which have been disclosed to us on a confidential basis.

incorporated into the interconnected network and paid for by multiple users in the event that the GIT was passed. The charges nonetheless would be imposed upon the connecting parties, whom may consequently not be prepared to outlay the deep connection charge (see discussion of 'first mover' problems in the following section).

Finally, and perhaps most significantly, when defining future market development scenarios for the proposed investment and alternatives the GIT only considers one transmission investment at a time. Suppose, for example, that Transpower was deciding whether to undertake two separate, but related investment projects, both of which were designed to increase transfer capacity to a particular location in the grid, but which were two-years apart. We understand that a separate GIT process would be applied to each project, which may give rise to the following problem:

- in each instance, the alternative investment for each individual project may be additional generation in the location that will principally be served by the transmission upgrade;
- when assessed *separately*, the NPVs of the proposed investments may exceed the expected NPV of additional generation; however
- when assessed *together*, the NPV of the two transmission projects may *not* exceed the expected NPV of additional generation.

In other words, if a *series* of transmission projects are all intended to address a particular problem – alleviating constraints into an importing region being the most obvious example – the way in which the GIT is presently applied *may not result in the best investment option*. Rather, because each transmission investment apparently is considered in isolation, critical interdependencies with other projects may be overlooked, which may skew the GIT calculus away from potentially superior alternative investments, such as additional generation in import constrained regions. This represents a potentially significant shortcoming with the way in which the GIT is undertaken at present. Ideally, it would be beneficial for the interdependencies between projects to be recognised in some way when undertaking the GIT. However, we have not explored the practicalities of doing so in this report.

The GIT is therefore not a perfect planning tool. However, whether consequential changes should be made to transmission planning arrangements and/or the TPM to address these shortcomings, including by introducing more explicit locational signalling in pricing, is another matter. Indeed, both Frontier (2004)[66] and Covec (2004)[67] have argued previously that the locational signals in New Zealand from nodal pricing and the GIT, although not perfect, are *adequate*. Covec (2004) noted that:[68]

> 'Thus, while not providing a complete solution in all cases, the existing nodal pricing system combined with a well functioned GIT do provide (at least qualitatively) appropriate signals to potential investors in new generators to locate plant efficiently.'

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[66] See: Frontier Economics, Transmission Pricing Methodology – Options and Guidelines, Final Draft Issues Paper, June 2004.

[67] Covec, *Locational Signals for New Investment,* August 2004.

[68] Ibid, p5.

In our view, although the GIT is undeniably an important transmission planning tool, we are *not* convinced that it alone is capable of doing all the work that is ideally required to provide economically efficient generation location signals. Specifically, we cannot be certain that the GIT (in combination with the nodal pricing arrangements and with the deep connection arrangements described below) plays a sufficiently prominent role in preventing sub-optimal generator location decisions. Further, we cannot be certain that it may not, in some circumstances, serve to dampen locational price signals by depriving generators in 'good' locations of the congestion component of their long-run marginal prices. Moreover, the circumstances and manner in which the GIT is undertaken may also be problematic. Most notably, because each transmission investment is considered in isolation, critical interdependencies with other projects may be overlooked and the wrong investment option selected.

4.3. Deep Connection Charging Arrangements

The existing TPM arrangements comprise deep connection charging arrangements, with a strong focus on the identification of beneficiaries. The principal reason for favouring deep connection charges was to encourage connecting parties to make ***efficient location decisions*** for their plant, by trading off the additional costs of locating at various points with the additional costs of connection.[69] Put simply, if a significant portion of the costs of connecting, say, a new generator is spread over all users (or on load), then new generators may pay less attention to where they connect.

However, the main problem with deep connection charges is that the deeper they go, the more contentious they become.[70] Indeed, whenever a 'line' is drawn that requires parties to pay more or less connection charges depending upon 'which side of the boundary' they locate, potential distortions can be created. The clearest example being potential distortions to generators' investment decisions, which we describe below.

4.3.1. Competitive Neutrality for Generation

Despite the potential benefits associated with the price signals provided by deep connection charges, care must also be taken to ensure that competitive neutrality is maintained between different forms of generation. In particular, in order for there to be efficient incentives for investment in the different forms of generation, including embedded generation, there should, to the greatest extent possible, be equality of treatment of the benefits[71] and costs[72] associated

69 Electricity Commission, *The Commission's Statement of Reasons in relation to the Proposed Guidelines for Transpower's Pricing Methodology*, 18 February 2005, paras 98 and 99.

70 For instance, it is reasonably clear that a line that connects a generator to the nearest junction of the transmission system is unlikely to be benefiting anyone but the generator concerned. However, it may also be true that even further into the network there are other lines that are built with the generator in mind. Perhaps they are needed as an alternative outlet for the energy if one line should fail, perhaps to take account of additional risks the generator's presence on the system creates, perhaps to share the load with another generator located a few kilometres away. The problem with proving *why* a line is built or who benefits from it lies with the fact that the generator concerned naturally will not want to pay for it. It is difficult to create a simple and transparent means of determining deep connection charges. See: H. Fraser, 'Can FERC's Standard Market Design Work in Large RTOs?', *Electricity Journal*, Volume 15, Number 6, July 2002 , p27.

71 Generators may provide a number of benefits to all those who produce, transport or consume electricity. First and foremost, they generate and sell energy. However, potential advantages also arise from a generator's choice of location including: an increase in available transfer capacity (where the chosen location substitutes for more distantly located generation); a reduction in network losses; and a reduction in network constraints.

with generation within the pricing framework. Put simply, generation alternatives that offer similar net market benefits should, all things being equal, pay the same connection charge. For example:

- suppose that a generator is weighing up whether to build a 100MW plant in location A or location B;
- a deep connection charging regime would require the generator to pay as much of the cost associated with connecting it to either location on the transmission network as possible, so as to provide the strongest possible locational signal; however
- if the two locations would offer precisely the same benefits and costs there is no efficiency justification for the connection charge differing between the two locations – indeed, this would provide inappropriate incentives to favour some locations over others to avoid paying charges.

In our view, the existing delineation between connection assets and interconnection assets, and the attending deep connection charging regime, risks producing these types of distortions to investment decisions. Indeed, under the TPM the quantum of connection charges that a generator is liable to pay can *vary significantly* depending upon the form of generation it selects, and its location, irrespective of the underlying net market costs and benefits. For example, a generator's connection charges will depend upon whether it connects its plant to:

- the interconnected grid directly at a GXP;
- the interconnected grid indirectly via dedicated or shared connection assets, ie, 'transmission connected' generation at a connection location; or
- the distribution network, and by-passes the interconnected grid, ie, 'embedded' generation.

The quantum of transmission charges likewise depends upon the 'ownership' arrangements for new connection assets. Charges can vary depending upon whether the generator enters into a NIC, in which case Transpower will build the necessary connection assets that become 'open access' thereafter, or whether it builds the assets itself.[73] Consider the simple grid configuration displayed in Figure 4.1. Suppose that there is an existing load at location E, and a prospective entrant is deciding whether to locate a new generation plant.

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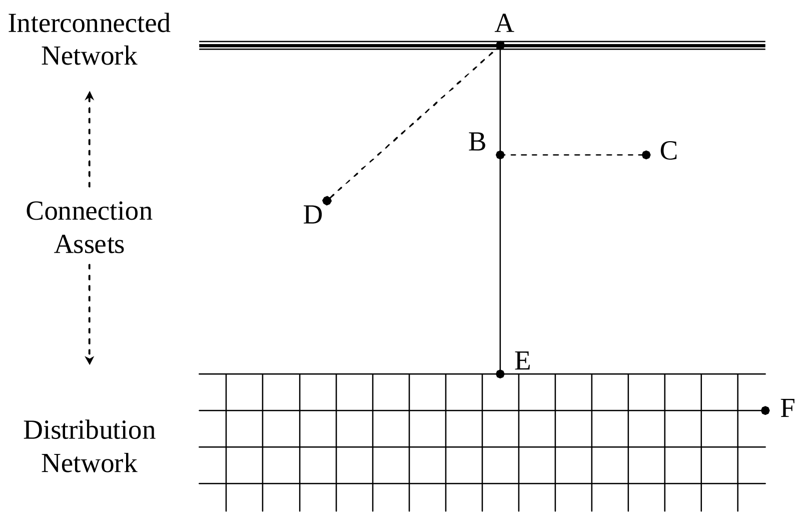
[72] Generators also cause costs. First, there is the cost of connecting the generator to the nearest appropriate point on the network. Additional costs may arise from a generator's choice of location including: costs of expanding upstream transfer capability, if undertaken; an increase in network losses; and an increase in network constraints.

[73] Or enters into a separate contractual arrangement for the construction of connection assets, eg, with a distributor.

Figure 4.1
Generator Location Decisions



Depending on the location decision ultimately made, the TPM would potentially result in significantly different connection charges for that generation proponent, which may have a material effect on the investment decision ultimately made. Suppose that the generation proponent's options are to:

- locate at grid exit/injection point A, and enter into a NIC such that Transpower built the necessary connection assets (ie, switchyard assets at the GXP), in which case Transpower would:
  - charge the generator new investment charges for capital recovery on the new switchyard equipment at the GXP; and
  - charge the generator injection overheads related to the new switchyard assets;
- locate at point C and again enter into a NIC with Transpower such that Transpower built the necessary connection assets (ie, the line from C ð B, and switchyard assets at the GXP), in which case Transpower would:
  - charge the generator new investment charges for capital recovery on the new C ð B link, and the switchyard equipment at the GXP;
  - charge the generator injection overheads related to the new switchyard assets; and
  - allocate a share of the connection charges (capital recovery and overheads) associated with the B ð A link to the new generator based on its AMI (with the balance being paid by the load at location E based on its AMD);
- locate at point D and build, own and operate a connection link between D ð A itself, with Transpower building the necessary connection assets at the GXP (ie, switchyard assets), in which case:
  - Transpower would charge the generator new investment charges for capital recovery on the new switchyard equipment at the GXP;

  - Transpower would charge the generator injection overheads related to the new switchyard assets;
  - the generator would control the D ð A line, which would be considered part of its power station; and
  - if the generator decided to provide access to another party, then under the *Electricity Act* it would not be permitted to retain the D ð A line, so it would sell the asset to a lines company or Transpower on its terms, and would provide access on its terms;

- locate at point D, and enter into a contractual arrangement with the lines company to build, own and operate a connection link between D ð A, with Transpower building the necessary connection assets at the GXP (ie, switchyard assets), in which case:
  - Transpower would charge the generator new investment charges for capital recovery on the new switchyard equipment at the GXP;
  - Transpower would charge the generator injection overheads related to the new switchyard assets;
  - if required, the lines company would be able to use its compulsory route acquisition abilities to acquire the necessary land (otherwise the land would be acquired on the market), then charge the generator for the line on the basis of a negotiated agreement; and
  - access to third parties would be granted on the basis of the commercial agreement between the incumbent generator and the lines company; and
- by-pass the interconnected grid by embedding itself directly into the distribution network at location F, in which case:
  - the generator would pay for the asset, maintenance and operating costs associated with the 'dedicated' assets need to connect to the distribution network,
  - the generator would pay injection overheads charges, but only if it injected power into the transmission grid, ie, if its AMI was positive; and
  - the lines company would be required to pay the embedded generator a sum that reflected any consequential reduction in transmission charges and/or network costs, eg, though any reduction in its contribution to the regional average RCPD, and so its annual interconnection charge.

Table 1 summarises the manner in which potential connection charges for the new generator can vary depending upon the location decision that is made.

Table 1
Connection Charges Associated with Location Decisions

	Generator Location			
	A	C	D	F
Sum of the asset, maintenance and operating costs associated with the 'dedicated' connection assets	ü	ü	ü[74]	ü
Share of charges for existing 'shared' connection assets	û	ü	û	û
Injection overhead at GXP	ü	ü	ü	ü[75]
Revenue reflecting the interconnection charges avoided by the distribution company[76]	û	û	û	ü

In light of the broad spectrum of potential connection charges for which generators may be liable to pay based on their locational decision and the type of generation, it is not difficult to envisage generators' investments being distorted inefficiently and inappropriate incentives being created, despite the good intentions of the deep connection regime. In particular, the existing arrangements appear to create incentives for:

§ generators to avoid charges associated with existing connection assets (particularly if they entail long spur lines) by either:
  - connecting at a grid exit/injection point on the interconnected grid (such as location A above), which may disrupt parallel flows on the interconnected network as compared with connecting via existing connection assets; or
  - connecting directly to distribution networks (such as location E above), which would also enable them to receive payments for the interconnection charges subsequently avoided by distributors;[77]

§ generators to build smaller plants with lower transfer capacity (and hence potentially smaller market benefits):
  - in order to calibrate their injections with the local load (particularly if a generator is embedded); or
  - in order to reduce their share of connection charges for existing connection assets, ie, to 'hide behind load' by reducing their AMI; and

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[74] The sum of the asset, maintenance and operating costs would be limited to the new connection assets required *at grid exit/injection point A*, ie, not the link between D and A, for which it would assume ownership. As explained further in section 4.3.2, because it would become the proprietor of the new connection asset it would have very little incentive to provide access to generators subsequently wishing to connect their plants in the same location. This may give rise to market power problems, eg, with the generator strategically withholding supply to affect market prices, and/or refusing to offer access to new entrants.

[75] Injection overhead charges will only be paid by the embedded generator if there is an injection into the transmission grid. If this never occurs, no injection charges are payable. A similar arrangement applies to HVDC charges.

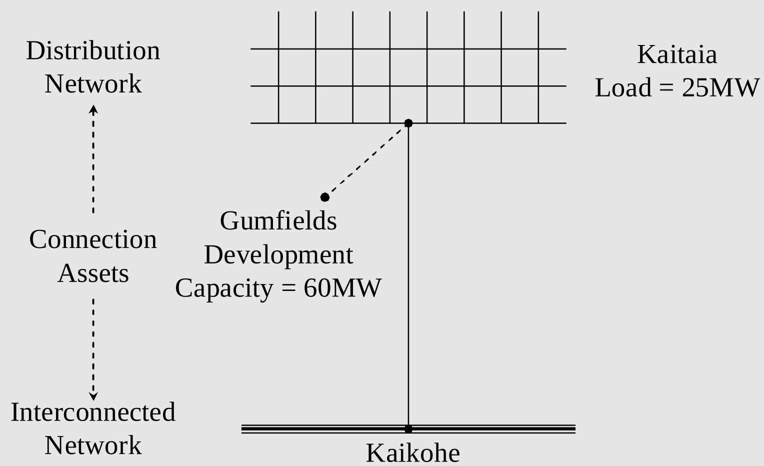
[76] Distributors are obliged to pay embedded generators a sum that reflected any consequential reduction in their contribution to the regional average RCPD, and so their annual interconnection charges. See: *Electricity Governance (Connection of Distributed Generation) Regulations 2007*, Schedule 4, Reprinted as at 28 May 2008.

[77] Note that the prudent discount arrangements described in section 3.2.5 only apply to the embedding of *existing generation*. New embedded generators are not eligible for prudent discounts, since to offer such discounts to discourage new embedded generation is considered contrary to the Government's policy on embedded generation.

- generators to avoid building near existing remote loads if that would result in them being forced to pay for connection assets already in existence (such as in location C above); and
- off-take customers to persuade Transpower to upgrade interconnection assets instead so that the costs are smeared across all users, even if it would be more efficient to install a new connection asset.

For these reasons, it is conceivable that generation investments with significant net market benefits may be foregone in favour of less beneficial alternatives that entail lower connection costs (including embedded generation), or abandoned entirely. Meridian's proposed 'Gumfields' development is illustrative. In this example, summarised in Box 4.1, local generation would improve local reliability and power quality, may defer long term transmission investment and would not necessitate any transmission upgrades, yet the transmission pricing arrangements may prevent the investment from taking place.

Box 4.1
'Gumfields' Development



'Gumfields' is a proposed 60MW wind farm, north of Auckland. The existing local load at Kaitaia is fed by a long, single circuit line from Kaikohe (which is in turn served by a 'long stringy' line from Maungatapere). Off-take customers pay for connection charges associated with the Kaikohe-Kaitaia link. Kaitaia has voltage and reliability problems and no local generation. In consequence, local generation would improve local reliability and power quality and potentially defer long term transmission investment. Under the existing TPM arrangements:

- currently, the 25MW load bears 100 per cent of the connection costs associated with the Kaikohe to Kaitaia link; and
- no new transmission would be necessitated by the Gumfields project, other than actual connection assets required, ie, the new link to the windfarm and switchyard upgrades at each GXP.

However, depending upon the investment option, different charging implications arise and different abilities to avoid interconnection charges. For example, if Meridian was the connecting party and Transpower built the necessary assets:

- Meridian would be charged injection overheads associated with the new equipment required at the relevant GXPs;
- Meridian would pick up ~70 per cent of the annual 'shared' connection costs (capital and overhead costs) associated with the connection link from Kaikohe (ie, 60 ÷ [60 + 25]), based on its AMI;[78] and
- Top Energy's (the local distribution company) allocation of connection charges associated with the Kaikohe to Kaitaia link would be reduced to ~30 per cent (ie, 25 ÷ [60 + 25]) for those assets that it 'shares' with Meridian.

Because connecting to the connection assets already in situ would result in Meridian assuming a large proportion of the connection charges for the 'shared' assets, it may have an incentive to:

- install a much smaller wind farm so as to reduce its AMI;
- enter into an arrangement with Top Energy to build the connection to the GXP; or
- install a much smaller wind farm and *embed it directly into the distribution network*, so as to avoid paying for any of the existing link and to receive additional revenue from avoided transmission charges; or
- if the project is uneconomic (even on a smaller scale), to abandon the initiative.

In other words, this is a situation in which local generation would improve reliability and power quality, would potentially defer long term transmission investment and would not necessitate any transmission upgrades, yet in which the transmission pricing arrangements have the potential distort the investment decision that is made, or possibly prevent the investment from taking place at all.

In addition to the distortions described above, a further potential problem with the existing delineation of network assets is that the charging arrangements for 'shared' connection assets may result in highly volatile charges as new customers connect and existing customers disconnect from the transmission network. The earlier example in Box 4.1 is illustrative once again. In that example, if Meridian was to connect 60MW of new wind generation by means of a new link that is at least partly 'shared' with existing load, then the allocation of the connection costs for the 'shared assets', and therefore the incidence of connection charges, would change dramatically.

Given the significant quantum of connection costs that will often be at stake, large windfall gains and losses are conceivable as load profiles changes over time, as new generators connect, and/or as existing generators disconnect. In other words, as the 'beneficiaries' identified under the deep connection charging arrangements change over time, so too will the associated connection charges. Such fluctuations reduce certainty and are unlikely to be conducive to facilitating efficient investment.

In some circumstances, it could be argued that individual parties themselves are capable of addressing the types of undesirable outcomes described above. For example, it may appear to be in the interests of a distributor to pay a new generator to locate its plant nearby and to connect via an existing connection asset. Doing so may improve local reliability and reduce the distributor's share of connection charges for the existing assets. However, the potential

[78] Note that this is despite the fact that it is unlikely ever to export 60MW along the connection link, ie, a proportion of Gumfields' output is likely to always be taken by the local load.

problem is that distributors do not clearly stand to benefit financially from any reduction in their transmission charges, because they are treated as 'pass-through' costs under the distribution pricing arrangements regulated by the Commerce Commission. As the name implies, each year such costs are directly 'passed through' to distributors' customers.

Specifically, a distributor's notional revenue for year ***t***, is equal to:

$$\sum_i P_{i,t}Q_i - K_t$$

Where:

i denotes each price pertaining to every specified service*;*

$P_{i,t}$ is the i^{th} price at the assessment date in year ***t;***

Q_t is the base quantity corresponding to the i^{th} price for the base year; and

K_t is the sum of all pass-through costs for year ***t****, including transmission charges.*

In consequence, any reductions (or increases) in transmission charges do not directly affect a distributor's profitability – it simply involves passing through a lower (higher) charge. This sets such costs apart from others such as operating and maintenance costs, since distributors ***do*** stand to benefit through higher profits from any reductions in these categories – at least for the duration of the regulatory period. In addition to receiving no direct benefit from any reduction in transmission charges, the distributor would incur additional transaction costs involved with negotiations.

However, it is conceivable that a distributor may benefit *indirectly* from paying a generator to locate nearby through improved local reliability and power quality. For example, if local generation resulted in say, less outages, a distributor:

§ may be able to transport more electricity, with attendant revenue benefits;

§ may be more likely to be comply with any 'quality path' set by the Commerce Commission under the distribution pricing arrangements (still under development); and

§ may build up 'goodwill' with its customers.

On balance, it is not apparent that a distributor has a *strong* incentive to encourage a generator to connect in circumstances such as the Gumfields scenario described above. Although there are *some* potential benefits, it is not clear whether they would be sufficient to warrant a payment to the generator to locate nearby, particularly given that there will be no *direct* financial benefit (since transmission costs are a 'pass-through') and additional transaction costs will be incurred. For these reasons, we do not consider that leaving such matters to private negotiations is necessarily the best solution.

Moreover, the Gumfields example is not an isolated occurrence. Rather, we have been provided with a significant number of similar examples of these types of distortions taking place throughout the transmission grid. Connection pricing anomalies also arise in relation to:

§ Meridian's potential Pouto, West Wind and Te Uku windfarm development and the connection line serving the Manapouri power station;

- the connection link serving Trustpower's Cobb hydro-electric power station north-west of Nelson; and
- the two principal GXPs into Christchurch – Islington and Bromley – one of which is considered an interconnection asset, and the other a connection asset, despite the fact that they essentially are identical from an engineering perspective.[79]

One option that warrants consideration is whether there may be merit in changing the prudent discount policy described in section 3.2.5 so as to avoid scenarios such as Gumfields. Presently, the policy is unlikely to be of assistance to Meridian, since it is unable to demonstrate to Transpower that it has a cheaper alternative means of exporting/importing power to the development (ie, a form of bypass) that is both achievable and to which it is prepared to commit.[80] It might be possible to develop some criteria that can be applied that would mean that, if allocations of 'shared' connection charges would render an investment opportunity uneconomic, then this might ***also*** qualify for a prudent discount.

In summary, the 'deep connection' charging approach presently employed by Transpower has an appealing simplicity, and does provide a locational signal to connecting parties. However, that locational signal is not perfect. In particular, because connection charges can vary substantially depending upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment incentives can be created in some circumstances. In addition, the arrangements for recovering the costs associated with existing 'shared' connection assets may give rise to significant step-changes in connection charges as 'beneficiaries' change over time. The key question is whether an ***alternative delineation*** would represent a material improvement, ie:

- a shallow connection regime would be simpler to implement, and may reduce (but perhaps not eliminate entirely) the extent to which connection charges are not 'competitively neutral' between different generation investment options, however:
  - the potential downside is that a greater proportion of costs associated with new connection would be 'socialised'; and
  - it may reduce significantly the locational incentives for new generators (and to a much lesser extent load); and
- if an alternative deep connection regime was put in place that involved drawing the 'boundary' in a different place – albeit while retaining a deep definition – incentives to avoid charges are still likely to remain, and so the question is whether they would be reduced.

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[79] Because other distribution networks also use the Islington GXP, it is considered an interconnection asset, whereas Orion is the sole user of the equivalent Bromley asset. We note that the TPM not only defines the Bromley substation as a connection asset, but also the 220kV spur line from that site, which is considered to be part of the core grid by virtue of the ~170MW load. In consequence, any upgrade to Bromley results in Orion paying 100 per cent of any such investment, whereas it would meet only ~10 per cent of any upgrade at Islington. In other words, virtually identical assets are treated very differently by the TPM.

[80] We understand that the 'alternative project' would involve the construction of an 110kV line at least 60km long. Since this is highly unlikely to be financially attractive for the proposed wind-farm, and so would not be something to which Meridian would be prepared to commit, it would be ineligible for a prudent discount.

Unfortunately, there is no easy solution to the question of deep versus shallow charges, as Fraser (2002) highlights.[81] In particular, there is no clearly-defined 'best' place to be along the spectrum from deep to shallow pricing, and any move from the status quo is likely to involve a degree of regulatory instability, which comes at a cost. The key question, which we consider in section 5.3, is whether an alternative approach would represent a material improvement, taking into account implementation costs.

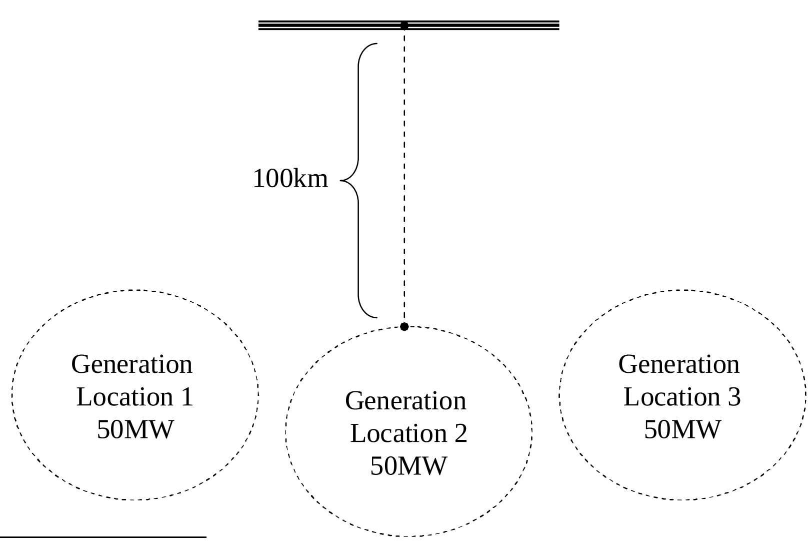
4.3.2. Potential 'First Mover' Problems

The 'deep' definition of connection assets means that connecting new generation in remote locations beyond the reach of the existing transmission network may require the construction of 'long spur lines' for which the connecting party will need to pay, consistent with the 'user-pays' philosophy underpinning the deep connection charging methodology. Specifically, a new generation proponent seeking to connect to the transmission network from a distant location would need either:

- § to enter into a NIC, in which case Transpower, in which case the spur line would be 'open access', allowing second- and third-movers subsequently to connect and share the capital and non-capital costs of that line with the first-mover consistent with the TPM; or
- § to build the spur line itself, in which case it would become the sole proprietor of the new asset, would not pay ongoing connection charges for the line and would only need to pay for any resulting upgrades needed at the relevant GXP.

It is unclear whether an efficient investment decision could reasonably be anticipated under either scenario, given the existing arrangements. To illustrate, consider the simple grid configuration set out in Figure 4.2 below. Three separate prospective new entrants each have the capacity to supply 50MW, provided a 100km spur line is built.

Figure 4.2
Potential 'First-Mover' Problem



[81] H. Fraser, 'Transmission Business Model', in *Making Competition Work in Electricity*, ed, S. Hunt, New York, Wiley, 2002, p199.

As section 2.2 explained, transmission investment exhibits significant economies of scale, and so higher capacity links are always cheaper in unit cost terms. For this reason, it may not be economic for an *individual* generation proponent to build (or ask Transpower to build) a 100km link sized so as to carry only its 50MW capacity. However, it *may* be economic to build a *larger* 100km link sized so as to carry the 150MW capacity of the three generation proponents *collectively*. However, the existing arrangements do not make is easy for such an outcome to be reached, since:

- unless the generators formed a consortium beforehand, one of the generators would need to be the 'first-mover' and request Transpower to build the larger line and pay the resulting deep connection charge;
- once constructed, the line will be 'open access' with subsequent entrants paying connection charges determined by the terms and conditions of NICs, which would in turn reflect the TPM; and
- any further compensation for the first-mover would need to be negotiated separately with subsequent entrants, which would appear to provide a strong incentive to wait until another business has made the investment, before entering.

If it *is* economic for one of the generators to itself build a line to serve its own capacity, then this may create other problems. Because it would become the proprietor of the new connection asset, it is not obvious that it would have an incentive to provide access to generators subsequently wishing to connect their plants in the same location – even if those generators were willing to pay for any upgrades required or other forms of compensation. Indeed, it is conceivable that the 'first-mover' may have an incentive to refuse access to new generators since they are prospective competitors. Moreover, by controlling the transmission link, that generator may be able to exercise significant influence over local nodal prices.

In other words, it is unclear whether the existing arrangements have a robust mechanism to allow 'bigger', more economic assets to be built to connect new generation locations, when smaller links would either be uneconomic or create scope for the potential exercise of market power if generators were to build such links themselves. For example, there presently is no scope for the GIT to be applied to such investments in such a way that the costs associated with links that may be beneficial to the market as a whole can be incorporated into the interconnected network and socialised. Rather, if the GIT is applied to such investments and met,[82] the charges are nonetheless imposed upon the connecting parties, whom may not be prepared to pay the requisite deep connection charge, for the reasons explained above.

4.3.3. Summary

The 'deep connection' charging approach presently employed by Transpower has an appealing simplicity, and does provide a locational signal to connecting parties of the costs of their decisions – albeit an imperfect one. However, because connection charges can vary

[82] As noted in 3.2.2, in order for a new connection investment to comply with the applicable grid reliability standards – and so clause 40.2 of the Benchmark Agreement – it must be an economic investment, under the economic limb of the GIT. However, we understand that *in practice* where both the connecting party and Transpower are in agreement that the investment should be made, the economic benefits are 'taken as read' and the formal cost-benefit analysis envisaged by the GIT is *not* undertaken.

substantially depending upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment signals can be created in some circumstances. In addition, the arrangements for recovering the costs of 'shared' connection assets may give rise to significant step-changes in connection charges as 'beneficiaries' change over time, which can reduce certainty and further harm dynamic efficiency.

The existing charging arrangements may also have the potential to create 'first mover' problems. Specifically, it is possible that beneficial investments may be foregone due to the absence of any formal mechanism to allow the construction of larger assets to new generation location, when smaller links would either be uneconomic, or create scope for the potential exercise of market power if built by generators themselves (or distributors). In other words, despite its potential advantages, the deep connection charging arrangements also pose a number of potential problems. The key question is whether an ***alternative approach*** would represent a material improvement. We consider this question in section 5.3.

4.4. The Role of the GIT

The GIT assessment process requires that all of economic costs and benefits of a proposed investment project, and its alternatives, are taken into account in the assessment of net economic benefits. This means that the relative costs and benefits of augmenting the transmission network in one location as opposed to undertaking alternative investments – either in the transmission network, in new generation, or in other initiatives – in other locations should be taken into account. In principle then, the GIT could be thought of as strengthening the locational signals provided by nodal prices and losses, and ensuring that any constraints in the network are 'built out' in the least cost way, rather than augmentation being driven by the prior location decisions of generators. In this sense, the GIT should therefore go some way to supporting new generation investment that is efficiently located.

However, whether this holds in practice is unclear. The GIT affects generators' locational signals primarily by altering the degree of congestion throughout the transmission system, and hence anticipated nodal price differentials. Of course, congestion can be a good thing for a generator, or a bad thing, depending on which side of a constraint it has located. In fact, if Transpower tends to over-build transmission for the reasons described in section 4.1, the effect is that the GIT will reduce congestion when it is uneconomic to do so, thus depriving generators in 'good' locations of the congestion component of their long-run marginal prices – and dampening their price signals to locate where they are needed most.

Moreover, although the market development scenarios that underpin the GIT can (and do) influence the investment decisions of generators,[83] ultimately, parties are still free to locate where they please. If a generator builds in a 'poor' location it might be the case that, once built (sunk), the GIT may indicate that a transmission upgrade is economic, whereas had it been assessed before the fact (before investment costs were sunk) a different conclusion may have been reached. Whether a generator would behave in this manner – and risk being constrained off, or being hampered by high loss factors if an upgrade does not eventuate (or

[83] The market development scenarios utilised within the GIT process have been an important consideration in several recent generation investment decisions made in the New Zealand market, the details of which have been disclosed to us on a confidential basis.

in the interim if an upgrade does eventually proceed) – is unclear, but if it anticipated that future transmission reviews might be favourable the scenario is certainly conceivable.

In addition, there are potential problems with the circumstances in which the GIT is applied. First, as 3.2.1 explained, strictly speaking, all new investments in connection assets should meet the economic limb of the GIT (although, in practice Transpower does not engage in vigorous economic testing). The question is whether the GIT *should* be applied to new connections and, if so, how. We address this question in section 5.3.2.3 and suggest some potential alternatives.

Second, there is presently no scope for the costs associated with 'nationally significant' or otherwise beneficial investments to be socialised if such investments pass the economic limb of the GIT. In particular, there presently is no scope for the GIT to be applied in such a way that 'large connection investments' (eg, to serve a new generation location), would be incorporated into the interconnected network and paid for by multiple users in the event that the GIT was passed. The charges nonetheless would be imposed upon the connecting parties, whom may consequently not be prepared to outlay the deep connection charge (see discussion of 'first mover' problems in section 4.3.2).

In summary, although the GIT is undeniably an important transmission planning tool, we are not convinced that it provides economically efficient generation location signals. Specifically, we doubt that it alone plays a sufficiently prominent role in preventing sub-optimal generator location, and it may in some circumstances serve to dampen locational price signals by depriving generators in 'good' locations of the congestion component of their long-run marginal prices.

4.5. Treatment of HVDC Assets

The purpose of the HVDC charge is to recover the cost of the HVDC link that connects the power systems of New Zealand's North and South Islands. As noted in section 3.1.3, in October 1996, the decision was made to recover all of the costs associated with the HVDC link from South Island generators. This decision was predicated on the belief that the bulk of the benefits from the HVDC link accrue to South Island generators (ie, the 'beneficiary pays' principle),[84] and that levying the charge on those customers would be non-distortionary. However, when assessed against the problem definition described in section 1.1, there appear to be a number of potential problems with the current charging arrangements, namely:

- the 'beneficiary pays' principle is not a robust means by which to determine the incidence of HVDC charges – the focus should be upon recovering the long-run investment costs associated with the HVDC link without causing inappropriate distortions, whilst providing appropriate locational signals of those costs; and
- the existing HAMI-based charging arrangements are said to result in the inefficient use of existing generation capacity, and to distort investment decisions, particularly in mid-merit and peaking plant.

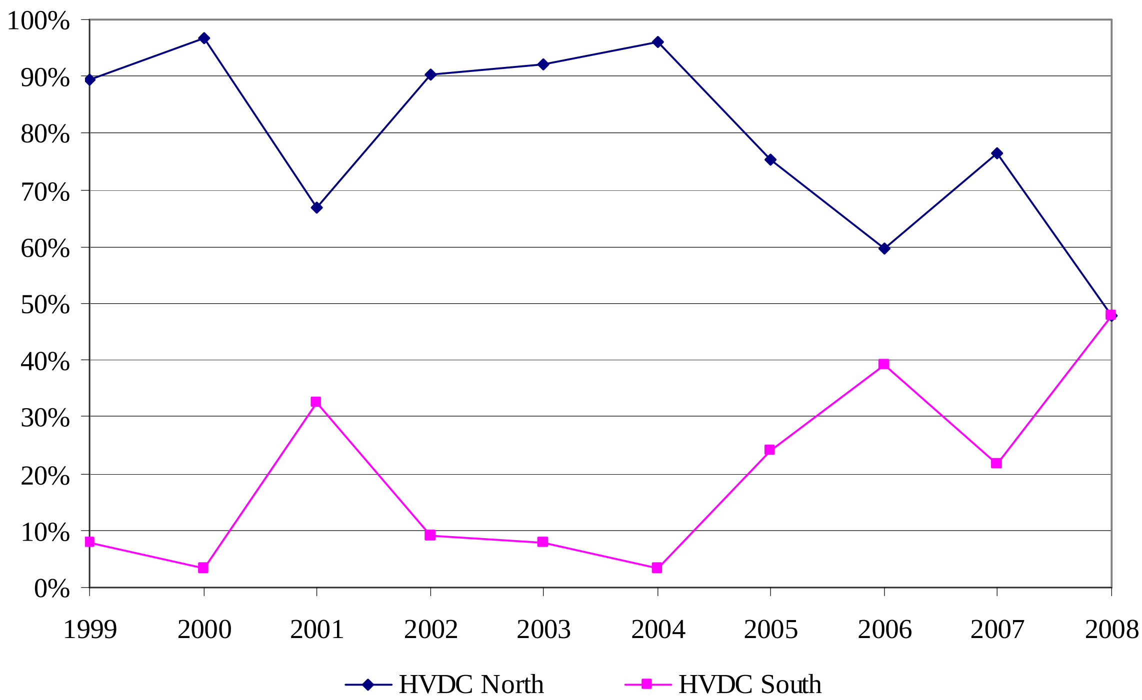
[84] Transpower New Zealand Limited (1996), *Pricing for Transmission Services: Introduction to the Pricing Methodology to be Applied from 1 October 1996*, An information booklet from The Transmission Services Group, p8.

However, despite these shortcomings, the HVDC charge does provide a *potentially* beneficial signal of the transmission cost differential between investing in the North Island as compared with the South Island. The key question that we examine below is whether that signal is *efficient*, or whether the disincentive it provides is *too strong*.

4.5.1. Beneficiaries of the HVDC Link

One of the reasons for allocating the full cost of the HVDC link to South Island generators from 1996 onwards was that they were perceived to be the principal beneficiaries of the link. In particular, because load flows were expected to be predominantly from south to north, the link would facilitate access to the more lucrative North Island market. There is certainly no denying that South Island generators historically have benefited from the HVDC link to a significant extent – they demonstrably have. Indeed, with the exception of the 1 in 60 dry-year in 2008, where approximately half of the flows on the HVDC link were north to south, the majority of flows have been, and continue to be, south to north, as Chart 2 illustrates.

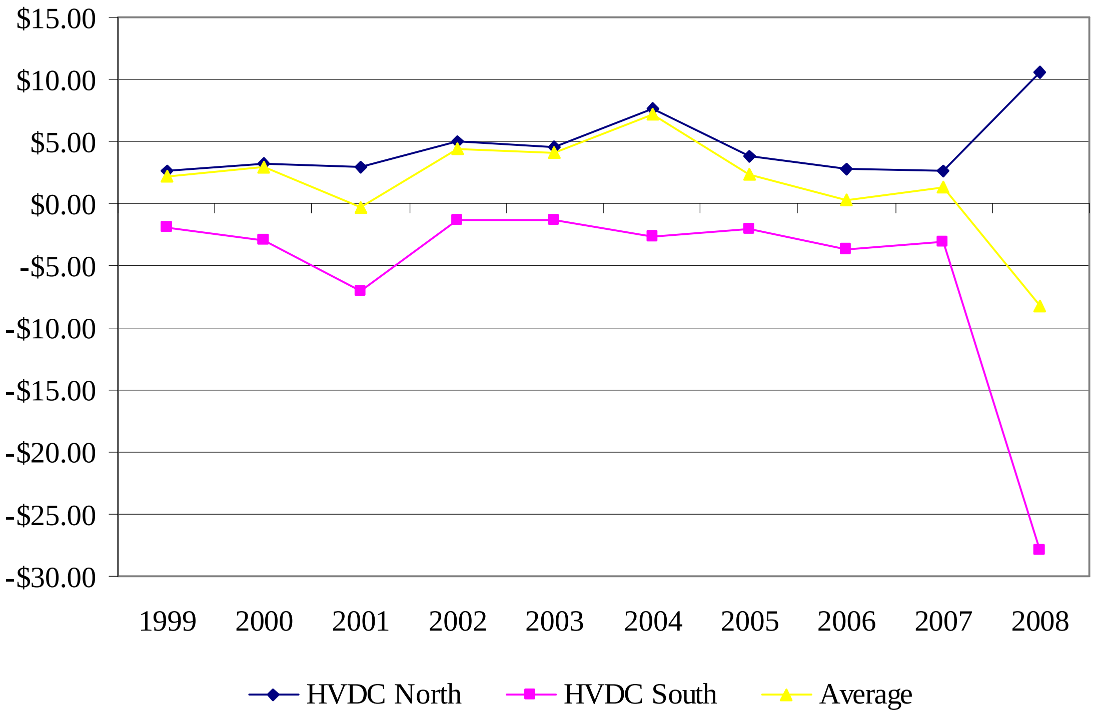
Chart 2
Direction of Flows on HVDC Link (% of Year)



However South Island generators, are not, and never have been the *sole* beneficiaries. Rather, they represent an easily identifiable subset of a potentially wide range of beneficiaries of the HVDC link. First, North Island load clearly also benefits since the link provides greater capacity at times of peak demand and gives them access to a cheaper source of generation. As noted above, in recognition of this fact, between 1993 and 1996 North Island load was allocated 53 per cent of total HVDC charges, with South Island generators making up the balance.[85] Indeed, the Electricity Commission (2007) has conceded that 'user pays' principles would support also levying HVDC charges upon North Island consumers.[86]

Second, whilst historic load-flows have, for the most part, been predominantly south to north, a number of recent dry-years have seen a material increase in north to south flows (albeit with the majority of flows still being south to north), as illustrated in Chart 2. Chart 3 illustrates the average nodal price differentials between Haywards and Benmore (which straddle the HVDC link) during periods of northwards flow, periods of southwards flow, and overall. It illustrates that during periods of southward flow, there is clearly a South Island price risk, and in extreme dry-years (such as 2001 and 2008), the average differential can be ***negative***, ie, prices are higher ***at Benmore***.

Chart 3
Nodal Price Differential Between Haywards and Benmore



This implies a new range of beneficiaries during these times; namely, in dry winters the HVDC link allows North Island generators to take advantages of higher prices in the South Island brought about by a lack of water in the South Island hydro-storage lakes. Similarly, South Island load benefits from the HVDC link in dry-years since it provides greater capacity at times of peak demand and gives them access to a cheaper source of generation. It is conceivable that, during these periods, South Island generators would benefit from not having the HVDC link in place.

85 Transpower New Zealand Limited (1993), *Transmission Pricing 1993*.

86 Electricity Commission, *Transmission pricing methodology: Final decision paper*, 7 June 2007, p23.

Third, the HVDC link also provides broader system-wide security and reliability benefits by augmenting the capacity of the transmission network – not only in dry-years, but generally. These wider public benefits are not easily attributable to individual beneficiaries, since they are enjoyed by all market participants. In other words, in our view there is a broad spectrum of market participants that benefit from the HVDC link – albeit some more than others and to varying extents over time. In consequence, the 'beneficiary pays' principle is not a robust means by which to determine the incidence of HVDC charges.

In particular, identifying the beneficiaries of the HVDC link – or of the transmission network generally (with the exception of connection asset) – and levying charges upon those parties in proportion to their 'private net benefit' will always be contentious and may simply not be practicable. At best, the 'beneficiary pays' principle might be used to ensure that the costs imposed on users are not demonstrably disproportionate to the benefits that they receive. However, even this may be difficult to assess in practice, as the Electricity Commission highlighted when examining analysis put forward by Meridian in relation to the pending HVDC link upgrade:[87]

> 'The assessment of private benefits is complex and subject to a number of key uncertainties. Any results at this stage can only be considered to be preliminary, pending more detailed analysis. In particular, the private benefit analysis carried out by Meridian and reproduced by the Commission is static in nature (ie, the effects of different HVDC link capacities on new generation are not internal to the model) …
>
> … [T]here are grounds to concur with Meridian's conclusion that the private benefit of a larger link size to South Island generators in terms of avoided spill costs may be less than their HVDC cost allocation (although probably not to the degree Meridian claims). However, the Commission notes that a larger link capacity may provide other private benefits and costs that have not been considered.'

In our view, although the concepts of fairness and equity that underpin the 'beneficiary pays' principle are not inconsequential, they should be secondary considerations in any decision regarding the charging arrangements for the HVDC link. Rather, any charging arrangement should focus carefully upon the criteria introduced in section 1.1, most notably, recovering long-run investment costs associated with the HVDC link without causing inappropriate distortions, whilst providing appropriate locational signals of those costs (to the extent they are not already provided elsewhere). The alternative is to engage in contentious and, in most cases, counterproductive debates about whom the beneficiaries are at any point in time – an inquiry that will always be subject to uncertainties, and prone to change over time.

More often than not, charges designed so as best to achieve the efficiency objectives set out above *will* involve allocating costs to the principal beneficiaries. However, if more efficient use of and investment in transmission infrastructure can be achieved by levying charges on parties that are not necessarily assured of obtain a private benefit, then these efficiency considerations should trump the potential inequity of such an arrangement. With this in mind, in the following sections we consider the extent to which the existing HVDC charging arrangements ***are*** likely to result in inefficient distortions to the use of and investment in transmission infrastructure.

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87 Electricity Commission, ***Transmission pricing methodology: Final decision paper,*** 7 June 2007, pp20-21.

4.5.2. Potential Distortions from the HVDC Charge

When the HVDC charging methodology was initially developed surplus generation and transmission capacity existed. That is no longer the case today. Strong demand growth has meant that new generation is needed throughout the country, and that transmission upgrades are also likely to be required. These circumstances mean that (amongst other things) it is becoming increasingly important to ensure that *use of the existing transmission network* is as efficient as possible, and that *new generation investment* is appropriately timed, well located and in the right technology. Of particular relevance is the fact that, from an overall generation perspective, New Zealand is starting to become a 'capacity constrained' system rather than an 'energy constrained' system.[88]

Historically, New Zealand has not had a capacity problem because of the high proportion of hydro capacity with associated flexible fuel supply (storage). New power stations have tended to be constructed in order to supply energy over time rather than to meet peak demand – in other words New Zealand has been considered as 'energy-constrained'. More recently, the retirement of the New Plymouth power station, the growth in peak demand, and the addition of intermittent generation in the form of wind farms, has eroded the margin between capacity and demand at peak times. The resilience of the electricity system to meet peak demands is expected to come under further pressure in the future.[89]

Indeed, the Electricity Commission recently concluded that 780 MW represents an optimal North Island capacity margin.[90] The estimated capacity constraint is in the North Island, and the assessment assumes that South Island generators contribute fully via the HVDC link. In other words, there is a well recognised growing need for additional peaking capacity to serve New Zealand's increasing peak demand (driven primarily by North Island load). To this end, the Electricity Commission has observed that, over the next few years, investment in generation in the South Island would be helpful.[91] In particular, it has recognised that South Island generators – especially hydro power plants – are likely to be well placed to meet peak demand relatively inexpensively:[92]

> '…the Commission anticipates a growing need for peaking type plant in the North Island. South Island hydro plant is well suited to this task, and there is excess peak capacity in that island…Investment in inter-island transmission capacity enables more existing South Island hydro plant to contribute to load following and peak demand in the North Island, deferring the need for specific new peaking plant to be constructed in the North Island.'

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88 See: Electricity Commission, *Development of a Capacity Adequacy Standard,* October 2008, p3.

89 Ibid. See also: Electricity Commission, *Annual Security Assessment 2008: Consultation Paper – updated to address questions raised during consultation,* November 2008.

90 The 780 MW capacity margin was derived from detailed simulations through to 2012 of the optimal level of supply capacity relative to MW demands and the economic implications of having more/less capacity on the system. See: Electricity Commission, *Development of a Capacity Adequacy Standard,* October 2008.

91 Electricity Commission, *Annual Security Assessment 2008: Consultation Paper – updated to address questions raised during consultation,* November 2008, p34.

92 Electricity Commission (2008) *Reasons for Decision set out in Notice of Intention to Approve Transpower's HVDC Grid Upgrade Proposal*, paras 5.3.3 and 5.3.4.

However, the existing HVDC charging arrangements are claimed by some South Island generators to distort their use of and investment in peaking capacity. The existing charges are said to penalise overloading or peaking operations located in the South Island. Specifically, if a South Island peaking plant knows that by injecting additional capacity at a connection node that it will increase its HAMI, and consequently face higher HVDC charges in the future, it is said to have a disincentive to do so. This is claimed to lead to generators engaging in physical withholding or generating in other locations so as to avoid creating a 'new peak' injection. For example:

- we understand that some South Island generators have physical alarms linked to supervisory control and data acquisition (SCADA) systems to alert generation controllers when injections are approaching the HAMI, to allow them to either:
  - reduce generation at the affected station; or
  - generate elsewhere; and
- Contact Energy has indicated that it seeks to limit its Clyde hydro power station to 400MW in order to avoid increasing its HAMI.[93]

To the extent that this conduct is widespread, this represents an inefficient use of existing generation capacity at a time when capacity constraints are becoming all the more important. The key question is *how commonplace* is such conduct likely to be in practice? Box 4.2 provides a simple illustration of the incentives that South Island generators may have to withhold supply in order to avoid significant step-changes in HVDC charges. It illustrates that, in order to have an incentive to withhold supply, a generator's expected capacity factor (most importantly during peak times) must be sufficiently low that the additional HVDC charges associated with increasing its HAMI will not be recovered. In our view, this is unlikely to be a common occurrence, in which case the potential distortions to use of existing peaking capacity brought about by the HAMI charging parameter *may not be all that significant.*

Box 4.2
Incentives to Withhold Supply

Suppose that a generator is serving a single connection location in the South Island with a 60MW peaking plant, ie, it has no other generation assets at any other locations in the South Island. Suppose also that:

- HVDC revenue is $80m;
- the sum of the HAMI for the relevant pricing year for *all HVDC customers* at all South Island connection locations is 3,500MW; and
- the twelve highest injections at that location for the pricing year were all 50MW, such that its HAMI was 50MW, ie, [50 x 12] ÷ 12.

In this example:

- the HVDC rate is $22.86/kW, ie, $80m ÷ 3500MW; and
- the generator's HVDC charge is $1.143m, ie, $22.86/kW x 50,000kW (50MW).

93 Contact Energy (2008) Presentation at the *HVDC Upgrade Conference*.

Suppose that during one half-hourly period the generator had injected 60MW at the connection location. The additional 10MW injection would mean that:

- the HVDC rate would decrease to \$22.79/kW, ie, \$80m ÷ 3510MW;
- the generator's HAMI would increase to 50.83MW, ie, ([50 x 11]+60) ÷ 12; and
- the generator's HVDC charge would increase to \$1.158m, ie, \$22.79/kW x 50,830kW.

In other words, by injecting an additional 10MW, the generator would incur an additional \$15,000 in HVDC charges, holding HVDC revenue and the HAMI of all other customers constant.[94] In order to recover the cost *during that period*, the generator would need to receive a price of at least \$3,000/MWh (ie, [\$15,000 ÷ 10] x 2), and wholesale prices of this magnitude are very rare.

However, if the generator thought that it could be dispatched for 60MW with sufficient frequency, it will still have a strong incentive *not* to withhold supply. Indeed, once the generator has produced 60MW in 12 periods, any *other* period in which it produces 60MW *does not attract additional HVDC charges*. If the twelve highest injections at that location for the pricing year were all 60MW this would mean that:

- the HVDC rate would decrease to \$22.10/kW, ie, 80m ÷ 3620MW;
- the generator's HAMI would increase to 60MW; and
- the generator's HVDC charge would increase to \$1.326m, ie, \$22.79/kW x 50,830kW.

In other words, by increasing its HAMI by 120MW, the generator would incur an additional \$168,000 in HVDC charges, holding HVDC revenue and the HAMI of all other customers constant. Ultimately, the generator must consider how many other periods it reasonably can expect to be dispatched for 60MW (ie, its expected capacity factor), and the expected wholesale price during those periods. The expected capacity factor would need to be extremely low before withholding would become profitable. For example, even if the generator expected only to be dispatched for 60MW 5 per cent of the time, it would still have 436 hours (or 876 periods) during which to recover the \$168,000 in HVDC charges, so provided the average wholesale prices was \$39/MWh or above (\$168,000 ÷ 436 ÷ 10), withholding supply *would not be profitable*.

The HAMI-based charge is said also to provide disincentives to ***invest in*** new South Island peaking generation. For example, we understand that periodic refurbishments of South Island hydro power stations often present the opportunity to install additional peaking capacity at a relatively modest incremental cost. However, the incremental increase in HVDC charges may make such expansions uneconomic since it may not be possible to obtain a commercial return. Alternatively, it may lead to generators embedding directly into distribution networks so as to 'hide behind load' and attract HVDC charges only for their net injections (and obtain off-setting revenue from the distributor for avoided interconnection charges).

It is also contended that generation proponents may be discouraged from undertaking South Island capacity firming investments if they are forced to pay HVDC charges even though they do not intend to export significant volumes to the North Island.[95] Indeed, the existing HVDC charge cannot account for 'transfers' of energy:

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94 Note that the overall incidence of the HVDC charge would differ if the generator had other South Island assets. Specifically, the additional HVDC charges allocated to the 60MW unit would reduce the quantum of HVDC charges allocated to *other* generation assets at other connection locations.

95 South Island load has grown significantly more quickly than North Island load in the last decade and potentially gives rise to the prospect of new generation being motivated by such factors, see for example: Contact Energy quote "South

- suppose a South Island generator built a 200MW open cycle gas turbine plant to support its hydro-plants during dry-years;
- when a dry-year does occur, the HAMI of its hydro-plants will not decrease (since the HVDC charge has a ‘five-year memory’), and the HAMI of the new gas plant may increase significantly;
- the net effect may be that the generator pays significantly more HVDC charges, even if it has not generated any additional electricity or potentially even if it has generated *less* electricity); however
- it should be remembered that the majority of HVDC flows are south to north, and new peaker will therefore have access to the North Island as well as the South (particularly in every year that is not dry).

In culmination, these factors may result in potentially inexpensive South Island generation capacity – particularly peaking capacity – not being built, or being embedded. What is less clear is whether this constitutes a potential shortcoming with the existing arrangements, or is rather a symptom of ***efficient locational pricing signals***. Indeed, the alternative in many instances will be to install capacity in the North Island, which may in fact be the superior outcome from a whole-of-system perspective. In other words, it is not self-evident that the factors outlined are symptomatic of efficient investment incentives, or inefficient incentives. In our view, for the reasons described in the following section, there is a reasonable prospect that the answer is the former.

Finally, the current HVDC charging arrangements create asymmetric consequences for ***new*** generators looking to invest in the South Island as compared with existing South Island generators looking to expand their portfolios. Specifically, the incremental effect of the HVDC charge on a new generation unit installed by a generator with a large existing portfolio of South Island generation assets may be less than for an equivalent investment made by a smaller generator, or a new entrant. This is because the HVDC charge is an ***allocation***. This means that there may be an off-setting effect for the large, ***existing*** South Island generator, since the HVDC charges allocated to the balance of its portfolio will decrease, as the example in Box 4.3 demonstrates.

Island electricity demand has grown over the last decade at 1.29x the North Island rate”, *Presentation at the Electricity Commission’s HVDC Upgrade Conference 2008.*

Box 4.3
Asymmetric Consequences of the HVDC Charge

Suppose that annual HVDC revenue is $80m and that the sum of HAMI for all *HVDC customers* at all South Island connection locations for the pricing year is 3,500MW. Suppose that Generator A has a HAMI of 3000MW and that Generator B has considerable smaller HAMI of 200MW. This would result in the following HVDC charges:

- the HVDC rate is $22.86/kW, ie, $80m ÷ 3500MW;
- Generator A faces an HVDC charge of $68,571,429, ie, $22.86/kW x 3000MW; and
- Generator B faces an HVDC charge of $4,571,429, ie, $22.86/kW x 200MW.

Now consider two investment scenarios:

- Generator A invests in a new 100MW plant that increases its HAMI from 3000MW to 3100MW, assuming that the twelve highest injections at the new connection location for the pricing year were all 100MW; and
- Generator B invests in a new 100MW plant that increases its HAMI from 200MW to 300MW, assuming that the twelve highest injections at the new connection location for the pricing year were all 100MW.

In both scenarios the HVDC rate becomes $22.22/kW, ie, $80m ÷ 3600MW. The *extent* of the asymmetry in the costs faced by Generator A and Generator B depends upon what is assumed to occur if the 100MW of additional investment in each scenario *does not occur*. As the table below illustrates, the asymmetry is greatest when the counterfactual is the 'status quo' (ie, when investment opportunities foregone by one generator are not taken up by another) and is zero when someone else is assumed to undertake an equivalent investment instead.

	Total HVDC Charges		
	"With" Investment	"Without" Investment (Status Quo)	Difference in HVDC Charges
Generator A	$22.22/kW x 3100MW = $68.89m	$22.86/kW x 3000MW = $68.57m	$68.89m - $68.57m = $317,460
Generator B	$22.22/kW x 300MW = $6.67m	$22.86/kW x 200MW = $4.57m	$6.67m - $4.57m = $2.10m
		Asymmetry between Generators A and B	$2.10m - $317, 460 = $1.78m

	Total HVDC Charges		
	"With" Investment	"Without" Investment (Someone Else Invests)	Difference in HVDC Charges
Generator A	$22.22/kW x 3100MW = $68.89m	$22.22/kW x 3000MW = $66.67m	$68.89m - $66.67m = $2.22m
Generator B	$22.22/kW x 300MW = $6.67m	$22.22/kW x 200MW = $4.44m	$.6.67m - $4.44m = $2.22m
		Asymmetry between Generators A and B	$0

The *true* extent of the asymmetry will lie *somewhere between* these two scenarios, ie, it will be positive, but not of the extent suggested by the 'status quo' counterfactual. The only situation in which an asymmetry *does not* occur is when each and every investment opportunity that is not taken up by one business is perfectly replicated by another. However, such a scenario implies perfect coordination, of which markets are generally not capable. For this reason, because Generator A has a large existing portfolio of existing generation assets, the increase in its annual HVDC charge following a new investment will be less than the increase faced by a smaller generator making an equivalent investment (eg, Generator B) or a new entrant.

The potential consequence of any asymmetry would be to increase the likelihood of new investment that does occur being undertaken by the incumbent South Island generators, and particularly Meridian. Meridian highlighted the existence of this asymmetry in a recent submission to the Electricity Commission:[96]

> 'The effect is that a new wind generation entrant in the South Island will face the full HVDC charge in their unit cost uplift (approximately $10/MWh) and Meridian (because it has the largest South Island generation portfolio) will face the lowest per unit cost uplift (at less than $5/MWh) due to redistribution effects inherent in the pricing methodology.'

Indeed, at best the existing HVDC charging arrangements provide the incumbents with a material competitive advantage when it comes to new investments and, at worse, may constitute a significant barrier to new entry and expansion. There is no simple way to address this asymmetry. The only way to avoid any possible distortion to investment incentives is to fix the monetary amount of recovery from each company, eg, by levying the charge based on nameplate capacity. However, this may lead to other problems, such as over- and under-recovery of required HVDC revenue.

In summary, the existing HVDC charging arrangements are said by some South Island generators to distort their use of and investment in peaking capacity. In ***principle***, the HAMI charging parameter does provide incentives to withhold supply of peaking capacity. However, in our view, the circumstances in which it will be profitable to do so are likely to be relatively infrequent and unlikely to warrant changing the parameter. Similarly, although the incidence of the HVDC charge may reduce incentives to invest in the South Island – particularly in peaking capacity – this is not necessarily a bad thing if North Island investment is preferable. Finally, the existing arrangements may influence ***whom*** investments are made by, although there is no straightforward way to address this asymmetry.

4.5.3. Locational Signal Provided by HVDC Charge

One consequence of the HVDC charge is that it provides an additional locational price signal to generators considering investing in the South Island. Indeed, the HVDC charge may sometimes make the difference between a marginally uneconomic generator locating in the North Island or the South Island.[97] If one is prepared to accept that a generator that locates in the South Island can ***generally*** be expected to impose greater costs on the transmission network than a generator that locates in the North Island, closer to the dominant load centres, and these costs are unlikely to be reflected in future nodal price differentials, then this is ***potentially*** beneficial.

Suppose, for example, that a generator was considering whether to locate in the South Island or the North Island. Assume also that a GIT process would indicate that the South Island

[96] Meridian (2007) ***Submission on the Electricity Commission's assessment of Transpower's proposed transmission pricing methodology***, p5.

[97] For example, we note that the Electricity Commission stated that the locational signal provided by the HVDC charge was an 'important aspect' of its decision to approve Transpower's proposal to continue levying the charge solely upon South Island generators in its TPM. See: Electricity Commission, ***Transmission pricing methodology: Final decision paper***, 7 June 2007, p24.

location was uneconomic, taking into account congestion rentals (the SRMC of transmission) and the additional long-run marginal cost of transmission associated with that location. Presently, the fact that the generator will also have to pay an HVDC charge if it locates in the South Island may be sufficient for it locate in the North Island – a superior outcome from a 'whole of system' perspective. However, *without* the HVDC charge, the signals provided by nodal prices, losses and the GIT may *not* be enough to prevent that generator from locating in the South Island (see sections 2.2 and 4.1).

In other words, absent the HVDC charge, any additional transmission costs imposed by generators that locate in the South Island may not adequately be signalled, and may lead to poor locational decisions by generators that are marginally uneconomic from a 'whole of system' perspective. On the other hand, if the locational signal provided by the HVDC charge is *too strong*, it will provide *too much* of a disincentive to invest in the South Island. Ideally, the HVDC charge should discourage marginally uneconomic generators from investing in the South Island when it would be more economic for them to locate in the North Island, but not be so large as to discourage investments that *would* be better located in the South Island.

Regardless of whether the current level of the HVDC charge is broadly appropriate, the fact remains that the locational signal it provides is relatively blunt. This reflects that an important limitation of the HVDC charge is that it does not provide ***intra-island locational signals***. Specifically, although it provides an incentive for generators to locate in the North Island, the signal is the same regardless of ***where*** in the North Island a generator locates. However, Transpower's long-term investment program (summarised in Figure 5.1), indicates that it may be preferable to encourage generation in the *north* of the North Island (and perhaps the north of the South Island), which the HVDC charge is not capable of doing. In section 5.1 we therefore consider potential reforms to the TPM that involve replacing the HVDC charge with a more sophisticated methodology, so as to provide a ***superior*** locational signal.

4.5.4. Summary

The 'beneficiary pays' concept that has featured prominently in past debates in the charging arrangements for the HVDC link is not a helpful principle by which to determine the incidence of such charges. The concepts of fairness and equity that underpin principle, whilst not inconsequential, should be secondary considerations in any decision regarding the charging arrangements for the link. Rather, the focus should be upon designing a charge that best meets the criteria set out in section 1.1; most notably, recovering the long-run investment costs associated with the link without causing inappropriate distortions, whilst providing appropriate locational signals of those costs.

The existing charging arrangements are said by some South Island generators to distort their use of and investment in South Island generation – particularly peaking capacity. Specifically:

- the HAMI charging parameter does *theoretically* provide incentives to withhold supply of peaking capacity, although, our estimates suggest that the circumstances in which it will be profitable to do so may be relatively infrequent *in practice*, in which case there is not a strong case for changing the parameter;

- the incidence of the HVDC charge may reduce incentives to invest in the South Island (particularly in peaking capacity), although this may well be symptomatic of ***appropriate locational signalling***; and
- the HVDC charge also increases the likelihood that new investment will be undertaken by established incumbent South Island generators (notably Meridian).

A potential *advantage* of the HVDC charge is that it does provide a locational signal to South Island generators. However, irrespective of whether that signal is thought to be too strong, about right, or even too weak, the most important point is that it *may* be feasible to introduce a pricing approach capable of providing superior, ***intra-island locational signals***. The advantage of this would be to encourage, say, generation investment in the ***north*** of the North (or South) Island – something that the HVDC charge is incapable of achieving. Such an option is discussed in section 5.1.

4.6. Interconnection Charges

Generators presently do not pay interconnection charges, so the only explicit price signals for new investment are provided by means of the TPM through the deep connection charging arrangements and the HVDC link (both discussed above). Rather, the charge is levied on off-take customers and is structured so as to reflect the varying locational cost of consumption at times of regional peak demand in four geographic regions. As section 3.1.2 explained, although the interconnection rate per kWh used to determine customers' annual interconnection charges is identical for all off-take customers at all connection locations in all regions, the share of interconnection revenue recovered from each customer ultimately is determined on the basis of their contributions to the average of the RCPDs in each region.

Because the average RCPD is calculated over 12 peak demand periods in the UNI and USI regions this provides off-take customers with an incentive to shift load to non-peak times so as to minimise their annual interconnection charge. Indeed, if an off-take customer does not reduce its contribution to the 12 peak demand periods, and other customers do, then it will pay a larger annual interconnection charge. In contrast, in the LNI and LSI regions in which the average RCPD is measured over 100 peak demand periods, there is not an equivalent incentive to reduce load, because it is unlikely to be feasible to control for 100 peaks.

Consequently, the interconnection charge provides an incentive for off-take customers to reduce consumption at peak times in those regions that will soon require substantial new transmission investment. However, it is unlikely that the existing interconnection charging arrangements realistically would have much (if any) bearing on an off-take customer's ***initial location decision***. In other words, although the interconnection charge may provide an incentive to reduce consumption at peak times, it provides little (if any) disincentive to off-take customers to locate in a congested region ***in the first place***. The question is whether any other features of the market arrangements are likely to do so and, if not, whether an ***additional*** price signal is needed.

Section 2.3 explained that the locational signals provided by nodal prices and losses (which may be reduced significantly if the LRA proposal is introduced[98]) were unlikely to influence

[98] See footnote 59.

the locational decisions of off-take customers. These signals could be augmented by departing from the uniform postage stamp methodology for determining the interconnection rate (the 'price') and deriving separate prices for different locations, depending on where peak load growth is to be discouraged. This may provide a more transparent locational signal to prospective off-take customers and make an off-take customer reconsider where to locate. The TPS methodology proposed by Read (2007) and summarised in section 5.1 is one potential means of delivering such a signal.[99]

However, in practice, even a TPS methodology is unlikely to have a material effect on the commercial incentives of ***off-take customers***. Put simply, for the reasons set out in section 2.3, off-take customers' locational decisions are unlikely to be much influenced by the anticipated quantum of interconnection charges ***no matter how they are structured***. However, once that locational decision has been made, the existing arrangements provide appropriate incentives to customers to reduce consumption during peak times, if they have located in a region susceptible to constraint. The more challenging question is whether there would be merit in introducing a further locational price signal if interconnection charges were ***also levied on generators***.

If generators also paid interconnection charges, then they are likely to be more responsive to any locational signals provided in those prices than off-take customers. There may therefore be merit in boosting the existing signals in nodal prices, deep connection charges and the GIT by adding a locational component to interconnection charges, and levying a proportion of those charges on generators – particularly if the HVDC charge was removed (see discussion in section 4.5.3). For example, in a similar fashion to the TPS methodology proposed by Read (2007) – interconnection charges could be levied upon load ***and*** generators dependent upon the region (or 'zone') in which they are connected. We examine this matter in more detail in section 5.1.

4.7. Summary

Many features of the existing transmission pricing arrangements are fundamentally sound, and are consistent with the objectives set out in section 1.1. For example, the arrangements ensure that system costs are recovered, and the nodal pricing and dynamic loss factor arrangements serve to minimise distortions to short-run operational signalling. The deep connection charging arrangements also provide additional locational signals by forcing connecting parties to trade off the additional costs of locating at various points with the additional costs of connection. The interconnection charging arrangements also provide appropriate incentives for off-take customers to reduce consumption at peak times in those regions that will soon require significant transmission investment.

However, certain aspects of the existing arrangements exhibit a number of potential problems that may result in the inefficient use of and investment in network infrastructure, namely:

- the combination of nodal prices, losses, deep connection charges and the GIT may not be sufficient to signal the LRMC of transmission investment;

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[99] E Grant Read, *Locational Transmission Pricing: A Formulaic Approach, prepared for Mighty River Power*, Draft 1.3, 26 February 2007.

- the HVDC charge is incapable of providing ***intra-island*** locational signals;
- the circumstances and manner in which the GIT is undertaken are potentially problematic – most notably, because each transmission investment is considered in isolation, critical interdependencies with other projects may be overlooked and the wrong investment option selected;
- the 'deep connection' charging regime has the potential to distort the long-run investment cost signals associated with different generation alternatives, specifically:
  - because connection charges can vary substantially depending upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment signals can be created in some circumstances;
  - the arrangements for recovering the costs of 'shared' connection assets may give rise to significant step-changes in connection charges as 'beneficiaries' change over time, which can reduce certainty and further harm dynamic efficiency; and
  - the arrangements may give rise to 'first mover' problems, whereby individual generation proponents are unwilling to pay the deep connection charges to connect new generation locations;
- levying HVDC charges on the basis of South Island generator's historic peak injections (HAMI) is said by some South Island generators to distort their use of and investment in peaking capacity, specifically:
  - the HAMI charging parameter does *theoretically* provide incentives to withhold supply of peaking capacity, although the circumstances in which it will be profitable to do so seem likely to be infrequent;
  - the incidence of the HVDC charge may reduce incentives to invest in the South Island (particularly in peaking capacity), although this may well be symptomatic of efficient locational signalling; and
  - the HVDC charge also increases the likelihood that new investment will be undertaken by established incumbent South Island generators (notably Meridian).

In other words, the existing arrangements have their share of strengths, and some potential weaknesses. In the following section we provide a high-level overview of options for reform to the current transmission pricing arrangements, targeted at addressing the potentially problematical aspects of the existing transmission pricing arrangements, without undermining the desirable aspects of those arrangements.

5. Potential Options for Reform

On the strength of the preliminary analysis in section 4, certain aspects of the existing transmission pricing arrangements in New Zealand appear to be potential candidates for reform. The touchstone for any proposed reform should be the potential for material improvement upon the existing arrangements when assessed against the criteria set out in section 1.1, ie, the enhancement of economic efficiency through providing superior commercial incentives for efficient use of and investment in transmission network infrastructure, including through the provision of efficient locational signals. In the following sections we introduce a number of high-level options for reform for consideration by the Steering Committee.

5.1. Introducing Further Locational Signals

It is apparent from the problem definition that industry and major consumer stakeholders would like to see a TPM that sends efficient locational signals, to the extent that such signals are not adequately provided elsewhere. On balance, we cannot be certain that the nodal pricing arrangements, when combined with the application of the GIT and deep connection charging, play a sufficiently prominent role in preventing sub-optimal locational decisions by generators and load.[100] Moreover, the locational signal provided by the HVDC charge is relatively blunt and, in particular, incapable of providing ***intra-island*** locational signals. This is potentially problematic given that the majority of TransPower's forecast investment programme is concentrated in the North Island (see Figure 5.1 below).

On its face, there appears to be material scope for the TPM to be modified in some manner so as to provide superior locational signals. Section 2.3 explained that the fundamental purpose of providing such a signal would be to change behaviour in a desirable way by altering commercial incentives. Accordingly, such signals are likely to be best targeted at ***new generators***. Indeed, the existing RCPD-based interconnection charging arrangements already provide appropriate incentives to ***existing load*** to reduce consumption in areas forecast to be prone to congestion, and it is unlikely that the initial locational decisions of new load will be influenced materially by transmission charges.

The objective of any signal would be to entice behaviour that reduces the future transmission expenditure that is needed, so as to improve the use of and investment in the grid, without creating other costs that exceed the avoided transmission costs. Naturally, any change to the TPM that involves the introduction of locational signals in transmission charges will involve short-term administrative costs as those signals are designed, implemented and administered. However, as section 2.3 explained, the potential long-term pay-off is that a more efficient pattern of transmission and generation investment may eventuate, such that dynamic efficiency is improved. Most notably, the objective would be to change in a material way the decisions made by generators (and/or load) so as to reduce or defer transmission costs that would otherwise be incurred.

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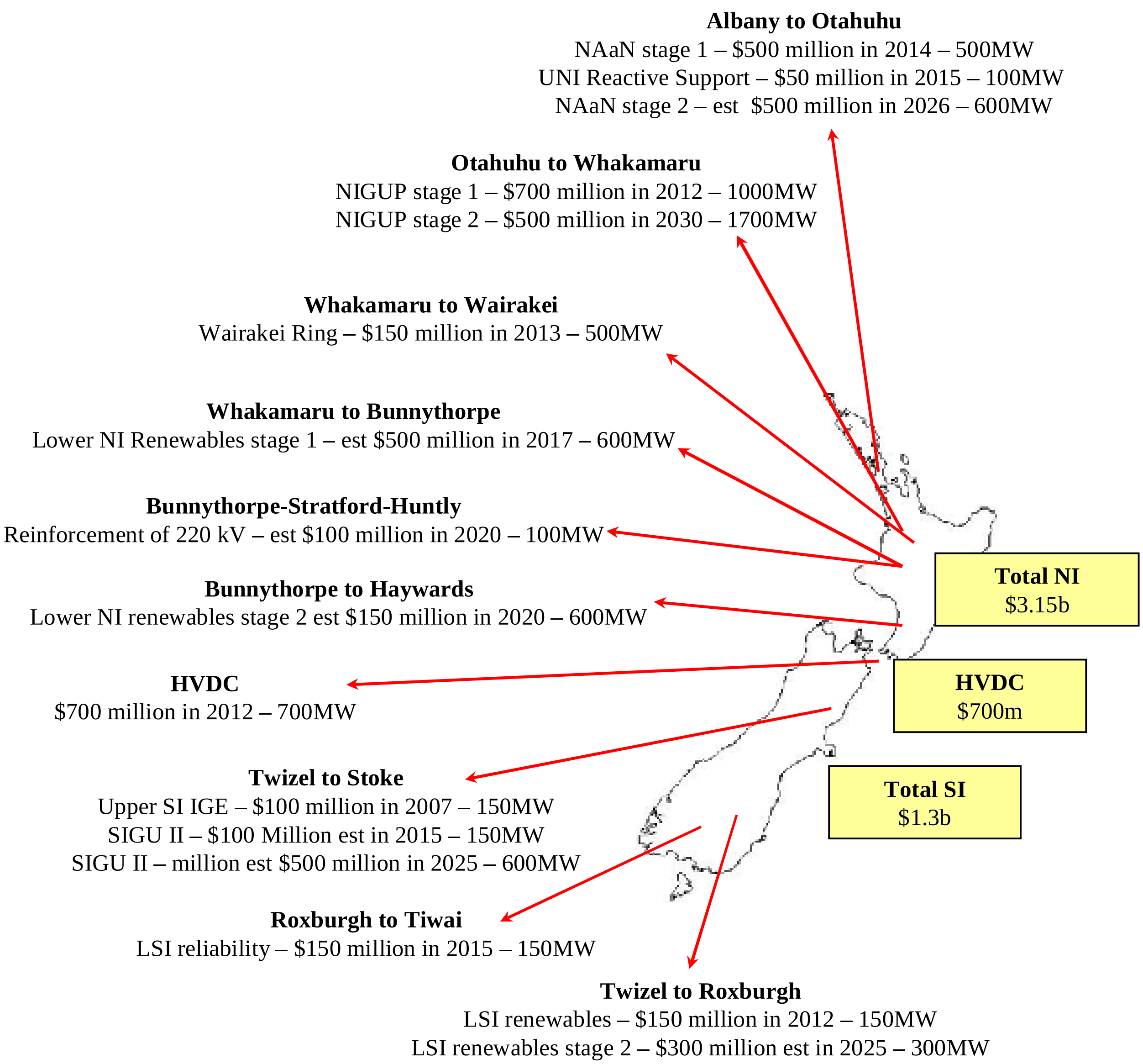
[100] Although, as we noted in section 4.2, Frontier and Covec have both argued previously that the locational signals in New Zealand from nodal pricing and the GIT, although not perfect, are ***adequate***. See: Frontier Economics, Transmission Pricing Methodology – Options and Guidelines, Final Draft Issues Paper, June 2004 and Covec, ***Locational Signals for New Investment***, August 2004.

With that in mind, a logical starting point for designing a locational price signal is to consider *where* Transpower is forecast to incur the majority of its transmission expenditure over the next 20 to 30 years. The preliminary forecast of upgrades required for the New Zealand grid is provided in Appendix A and summarised in Figure 5.1. It suggests that Transpower has a significant forward-looking investment program *in the North Island* – particularly in the central- to upper-North Island – that we understand is caused in large part by the expectation that generators will be locating remotely from major load centres.

Figure 5.1
Major Forecast Upgrades to Transmission Network, to 2035



Whilst only indicative, and subject to a number of caveats,[101] Figure 5.1 shows that $3b is forecast to be spent on the AC network north of Bunnythorpe between 2009 and 2035. Clearly this is a significant outlay. In other words, Figure 5.1 suggests that if the TPM could be designed so as to provide generators and/or load with incentives to locate in places that might avoid or defer the need for this substantial forward-looking investment, this would potentially be *very beneficial*. For example, if a generator could be encouraged to locate at, say, Albany, this might be expected to avoid or defer more transmission investment than if the generator chose to locate at, say, Twizel. The key question is: ***can such a locational signal be designed without creating adverse consequences such as compromising security?***

A proposal that has recently been put forward to enhance locational signals in interconnection charges is a 'tilted postage stamp' (TPS) pricing regime.[102] The essential difference between the TPS pricing regime proposed by Read (2007) and the existing pricing arrangements is that instead of there being a *single national price* for transmission interconnection, the price would vary on a simple 'tilted' geographic basis. The potential advantage of such an approach over, say, the locational signal provided by the HVDC charge is that it is capable of providing ***intra-island*** signals so as to provide greater encouragement to generators (and to a lesser extent load) locate in those places in most need additional investment. We describe the mechanics of a TPS pricing regime below.

5.1.1. A 'Tilted Postage Stamp' Pricing Methodology

The TPS pricing methodology is intended to provide broad national locational signals of long-run investment costs, to the extent that these are not already provided by the existing arrangements. The TPS methodology described by Read is primarily described in relation to locational signals for *load entities*. However, there would seem to be more merit in applying such a methodology to *generators*, since:

§ the existing RCPD-based charging arrangements already provide appropriate incentives to *existing load* to reduce demand during peak periods in locations forecast to become susceptible to congestion; and

§ new generators are more likely to be responsive to price than *new* loads, thereby delivering greater potential efficiency gains.

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[101] The grid enhancements are indicative only, ie, they are not necessarily committed and not necessarily 100 per cent accurate. They are subject to a number of provisos, including:

§ the objective is to provide a rough order of magnitude in order to develop a preliminary TPS methodology (see below);

§ only investments dealing with main trunk have been included – upgrades to customer connection/grid interconnection to meet demand have been ignored, ie, the list included only those investments driven by generation location decisions;

§ the underlying premise is need for strong south to north capability with generation more likely to locate south in absence of any other drivers; and

§ the investments assume 'normal' load growth, eg, they do not anticipate new technologies that reduce peak capacity, etc.

[102] See: E Grant Read, ***Locational Transmission Pricing: A Formulaic Approach,*** prepared for Mighty River Power, Draft 1.3, 26 February 2007. The TPS pricing proposal also has international precedent – notably in the United Kingdom and Ireland where MW-mile methods are used to vary interconnection charges (to both generation and load) based on estimates of locational LRMC of transmission.

For this reason, although we recognise that it would represent a substantial departure from the existing TPM, in the following section we set out a conceptual 'straw man' methodology for applying such a methodology to generators, and undertake a (highly preliminary) application.

5.1.1.1. Conceptual 'Straw Man' TPS Methodology

The objective of the TPS methodology is to establish a simple 'south-north' signal or 'tilt' that broadly aligns with the current missing element of the LRMC signal (assuming such a 'gap' exists). In the first instance, this involves determining a 'stylised network topology' based on a simplified 'main trunk' representation of the transmission system to reflect:

- the *general direction* of flow; and
- the *principal driver* of transmission investment; and
- the general direction of increasing LRMC.[103]

In our view, although load-flow analysis might usefully inform the initial development of a simplified topology map, this should only be for the purpose of identifying a broad structural characterisation of the grid. It is important to resist the temptation constantly to update the topology map on the basis of a load-flow analysis so as to adjust the relative positions of connection points. This would introduce the prospect of frequent changes in interconnection charges. As a matter of both principle and practicality, this would be undesirable and inconsistent with the objective of achieving an enduring pricing methodology. The experience in the UK and Ireland is apposite.[104]

Figure 5.2 below provides an example of a simplified grid topology. The transmission grid is divided into eight 'zones', extending from the bottom of the South Island to the top of the North Island. Critically, the average direction of flows is assumed to be ***south to north***, implying that the LRMC of transmission ***increases***, as one ventures further south. As we explain further below, this involves the strong assumption that the principal purpose of the 'main trunk' is to provide a 'highway' to allow northward power flows. Put another way, the principal driver of the investments set out in Figure 5.2 is assumed to be to facilitate south to north flows caused by the expected location of substantial new generation capacity in the South Island. Locational interconnection prices (or the 'tilt') would be applied on the basis of the connection points/zones on the south-to-north longitude of this simplified network topology diagram (or some other simple representation), rather than simply on the basis of the ***physical longitude*** of connection points on a map of New Zealand.

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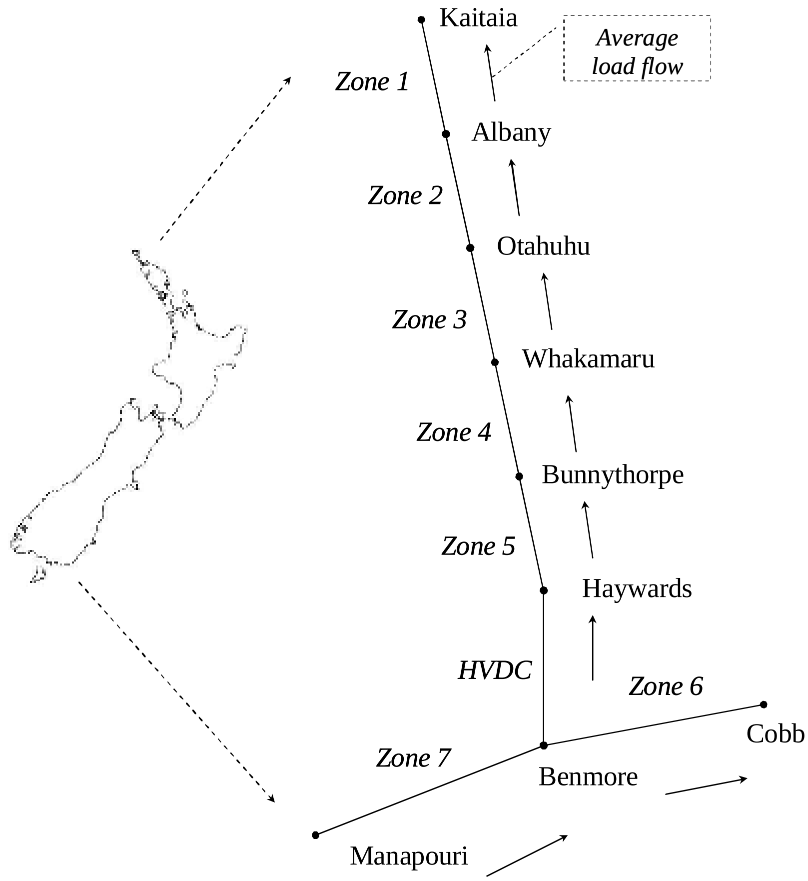
[103] The distinction between the AC and DC networks should be eliminated by virtue of its incorporation within the stylised network topology.

[104] The use of complex simulation models to determine locational LRMC estimates in the UK and Ireland has led to conflict over assumptions used, techniques applied, and so on. In some cases, and particularly in Ireland, small changes in model inputs from year to year have led to volatile transmission prices at certain locations – a particularly undesirable outcome given that generation and load investment is sunk once a location has been selected. The purpose of the locational signal should be to encourage investment in appropriate locations, and minimise uncertainty once that investment has taken place. Volatile network charges fail on both counts. The TPS regime described below is specifically intended to avoid this volatility.

Figure 5.2
Simplified Transmission Grid Topology



The appropriate differences in prices between the various connection points/zones (or the 'slope') is an empirical issue, but they should be set by reference to the assessed difference between the *LRMC of connecting generators that locate in each zone*, net of the signals already provided by expected spot price differentials (ie, by reference to the 'gap' between LRMC and SRMC). This could be broadly estimated as follows:[105]

- determine the net present value (NPV) of the forward-looking investment required to update/expand the Figure 5.2 'main trunk' (or some other simplified representation) over the next decade or two, eg, based on Transpower's forecast investment requirements for the interconnected grid summarised in Figure 5.1, and using a discount factor based on Transpower's regulatory weighted average cost of capital (WACC);
- determine the revenue ($/MW/Year) required to support this future investment based on capital (WACC) and O&M costs;
- for each zone along the 'main trunk', estimate the quantum of the forecast annual transmission costs that *would be avoided throughout the whole transmission network* if a

105 Note that estimates ultimately will need to be converted to a $/kW basis to determine prices.

generator of a capacity equivalent the additional transmission capacity needed in that zone located immediately above (north) of that zone – as described further below, this might be done on the basis of the market development scenarios contained in the SOO and which are used by Transpower in its planning processes;[106]

- if one assumes a general south-north flow, progressively more of the costs set out in Figure 5.1 should be avoided the *further north* that a generator locates, for example:
  - a 500MW generator located at Albany may avoid most or all of Transpower's forward-looking investment costs;
  - a 1000MW generator located in Wellington may avoid some but not all of the forward-looking costs; and
  - a 1000MW generator located at Benmore may avoid very few if any of the forward looking investment costs, given the assumed pattern of flows; and
- the avoided costs provide an estimate of the LRMC of generators' location decisions ***in each zone*** along the 'main trunk', ie, if more costs are avoided the ***further north*** that a generator locates, then the LRMC estimates should ***increase for locations further to the south***, which should lead to ***higher*** interconnection prices in southern zones, on average, than in northern zones.

Finally, the LRMC calculation set out above should be adjusted to account for the locational signal ***already provided*** by nodal price differentials. This can be accounted for by:

- calculating the average historical nodal price differentials between zones (ignoring rentals since generators do not receive them) for as many years as possible;[107] and
- for each zone, deducting the average nodal price differentials (ie, the SRMC signal) from the estimated LRMC.

The calculation described above should, *at least in principle*, provide a reasonable indication of whether a generalised TPS methodology is worthwhile. Specifically, before such a methodology is employed it must be the case that:

- the existing price signals are inadequate, ie, there is systematically a 'gap' between the LRMC of generators' location decisions in each zone and the average nodal price differentials – otherwise there is no need for an additional price signal; and
- the 'gap' between the LRMC of generators' location decisions and the average nodal price differentials ***increases in a systematic way*** along the simplified main trunk, indicating that the price signal should be ***tilted*** – if the 'gap' is constant, then there is

[106] It is necessary to exclude any investment costs that would remain unaffected the generator's location decision. The capacity hypothetically installed by each generator should also be discounted (eg, by the WACC) to reflect the *timing* of that investment. For example, if a transmission investment project that is forecast to occur in 10-years time could be avoided by undertaking a generation investment in, say, 5-years time, then that additional generation capacity should be discounted by 5-years to ensure comparability with the transmission investment that it is displacing.

[107] For convenience the spot price differentials in $/MW/h should be converted to $/MW/Year to allow them to be easily compared to the capacity costs of transmission ($/MW/Year). This can be done by multiplying the $/MWh prices by the hours in a year and the assumed capacity factor of the transmission.

again no need to provide an additional price signal, since there will not be any ***particular*** locations where investment needs to be encouraged/discouraged.[108]

Note that the most important aspect of the calculation above is the ***relative difference*** in the postulated price signal in each zone. Regardless of the ***price level***, the ***difference*** in the $/kW prices between zones should reflect ***the $/kW difference in the LRMC (net of SRMC) of transmission costs in one zone compared to another.*** For example, if a 1000MW generator locating in Kaitaia would avoid ***all*** of forward-looking investment costs, such that the LRMC of transmission was $0/kW, and a 1000MW generator locating at Manapouri had an associated LRMC of $30/kW, then:

§ one means of providing a locational signal would be to charge the Kaitaia generator an interconnection charge of $0/kW and the Manapouri generator $30/kW; and

§ another means of providing the same signal would be to pay the Kaitaia generator $10/kW and to charge the Manapouri generator $20/kW (this option is discussed further below as a potential means by which to preserve the existing RCPD signal for load).

In each instance, the ***relative price difference*** is the same, ie, the $30/kW difference in the LRMC of the transmission consequences of generation investment at Manapouri as compared with Kaitaia. In other words, in determining the final prices that should be charged to generators, the interconnection price ***level*** is less important than the ***relativities*** between the prices in each zone.[109] For example, assuming that the LRMC increases as one journeys south, the simplest approach to administer might be to set a price of $0/kW in the northernmost zone, and to increase the price incrementally (based on the calculated relativities) for each successive zone to the south. On that approach, one must:

§ determine the means by which the charge will be levied, eg, nameplate capacity or peak injection based charges are likely to be the least distortionary (an energy-based charge should not be used since it will alter bidding conduct);

§ for each year (or potentially a longer period), forecast the interconnection revenue that is likely to be recovered from generators, given the determined prices;

§ determine the quantum of interconnection charges to be recovered by load through the RCPD arrangements, which would be equal to Transpower's total interconnection revenue requirement less the TPS interconnection revenue forecast to be recovered from generators, ie, a ***residual***; and

§ create an 'unders and overs' account in order to deal with any under- and over-recovery from generators (relative to the forecast above) in each year.

In determining the quantum of interconnection charges to be recovered by load (the third step above), it is important to be mindful of the desirable properties of the ***existing*** interconnection charging arrangements. We explained in section 4.6 that the existing RCPD-based charging arrangements provide appropriate incentives for off-take customers to reduce consumption at

[108] Note that the calculation may also imply that zones or connection points should be consolidated or excluded before a TPS is implemented.

[109] Biggar makes the same point in his paper recently prepared for the AEMC. See: D.Biggar, (2009), A Framework for Analysing Transmission Policies in the Light of Climate Change Policies, Draft, April, pp23-24.

peak times in those regions that will soon require significant transmission investment. Any move to a TPS methodology that involved recovering a proportion of interconnection costs from generators may reduce the extent of that signal, and so reduce the effect of the current arrangements.

Put simply, if the quantum of interconnection charges recovered from load was reduced by, say, 50 per cent, then this will reduce the incentives provided by the existing arrangements, since the potential financial reward (penalty) from reducing (increasing) contributions to the average RCPD will be materially lower. There are two potential means of ameliorating the extent of this trade-off:

§ reduce the number of peaks in the RCPD-based charge levied on load so as to sharpen the signal (although, any such 'sharpening' is likely to be more than off-set by any material reduction in the total quantum of charges recovered from load); and/or

§ set the price ***levels*** for generators in each zone so as to ensure that the interconnection charges recovered from load did not decrease significantly under the TPS methodology – in principle, this could be achieved by levying charges upon generators in southern locations and ***making payments*** to generators in northern locations so that the quantum of interconnection charges to be recovered from load ***remained largely unchanged.***

On balance, and recognising the potential trade-off with the existing RCPD-based arrangements, the TPS methodology represents a ***conceptually*** sound, but relatively straightforward way of providing appropriate locational signals to generators through the interconnection charge. Its key strength is that it relies upon a ***simple formula-based*** approach rather than the periodic application of complex modelling of forecast load flows, which would introduce undesirable volatility and uncertainty into prices. It might be said that the over-arching criterion for the development of the formula for the tilt would be that 'the perfect is the enemy of the good'.

However, although the methodology is based upon a stylised grid topology, it is still critical that this represents a ***broadly accurate and accepted structural characterisation*** – at least for, say, a 10 to 20 year period. If such a simplification cannot be made, then the methodology described above ***cannot be implemented without distortion.*** The other critical steps are determining the extent of the 'tilt' to be applied across the simplified topology, and specifying the process by which the tilt will be reset. We discuss these key challenges in more detail below and suggest some processes by which they might be addressed.

5.1.1.2. Key Challenges

Perhaps the greatest challenge in implementing a TPS methodology is arriving at the stylised network topology. A critical underlying assumption in Figure 5.2 is that there is a ***structural northward power flow*** along the main trunk of the New Zealand transmission grid. In other words, many (if not all) of the investments summarised in Figure 5.1 are assumed to be for the purpose of 'maintaining or upgrading' the 'south-to-north highway'. If that assumption is correct, the calculations set out in the previous section become significantly easier, since one is likely to able to infer more readily when estimating the LRMC for a zone the quantum of forecast transmission investments that is likely to be avoided or deferred throughout the system (ie, to the south) by generation investments. By way of example, if 100 per cent of the forecast transmission investments south of the Bombay Hills are to facilitate the transfer of power to Auckland, then a 1000MW baseload generator located in Otahuhu may avoid or defer most of Transpower's forecast transmission program.

Conversely, if the generalised structural characterisation of the main trunk grid implied by Figure 5.2 (or any similar representation) *cannot* be assumed to apply for a reasonable period (eg, 10 to 20 years) then it becomes *very difficult* to calculate the LRMC of transmission in a zone. For example, if the scheduled upgrades set out in Figure 5.1 are intended to facilitate multi-directional flows and/or to meet deterministic reliability standards, it may become very difficult to infer with any certainty the quantum of *costs that would be avoided* by generators' locational decisions from zone to zone, and so the appropriate locational price differentials throughout the grid. For example, if, say, the reinforcement of the 220kV link between Stratford and Huntly is to improve reliability and enable multi-directional flows, it may be very difficult to hypothesise the proportion of this forecast cost, (if any) that would be avoided or deferred by a generator locating to the north of Huntly.

Appendix B provides a summary of historical power flows between 1 January 2000 and 31 December 2009, provided by Meridian. It illustrates that historically there have multi-directional flows over the HVDC link and into and out of Wellington, Auckland, the central North Island and Southland. There is little doubt that power flows may not ***always*** be south to north. However, that is not the critical test for whether a TPS methodology can be successfully applied. What matters is the *principal driver of transmission investment*. If the investments described in Figure 5.1 are principally to facilitate northward flows – recognising that power may sometimes flow south – then a TPS methodology that provides incentives to generators to locate further north may avoid or delay the need for that investment, thereby improving dynamic efficiency. In other words, although the existence of significant multi-directional flows may weigh against a finding that a structural northward flow exists, they are not in themselves determinative.

In our view, Transpower is likely to be in the best position to produce an enduring characterisation of the grid. This might be achieved on the basis of its 10-year plus transmission development plan. Interestingly, the EC's 2008 SOO, which is used by Transpower in its planning processes, seems to provide *some* support for the structural northward power flow illustrated in Figure 5.2.[110] It contains five 'market development' scenarios that represent the Electricity Commission's view on how the market might evolve in the future. The generation scenarios and demand forecasts contained in the SOO are the 'default' market development scenarios used to analyse grid upgrade proposals, and form an integral part of the GIT. The 2008 market development scenarios are summarised in Table 3.

Three of the five scenarios appear to be at least broadly consistent with the hypothesis that a significant proportion of the transmission investment expenditure in Figure 5.1 is driven by the desire to facilitate a structural northwards flow. In particular, the South Island Surplus, Sustainable Path and Medium Renewables scenarios imply grid investment that is driven significantly by renewable investment in the South Island. The Demand Side Participation scenario may also involve significant South Island investment if lignite is developed. In other words, the regulatory view of generation development – and consequently transmission

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[110] The purpose of the SOO is to enable the identification of potential opportunities for efficient management of the grid, including investment in upgrades and investment in transmission alternatives.

needs – appears to lend support for a simplified topology based upon a structural northward flow driving transmission needs.

Table 2
SOO Market Development Scenarios

Scenario	Description
Sustainable Path	New Zealand embarks on a path of sustainable electricity development and sector emissions reduction. Major existing thermal power stations close down and are replaced by renewable generation, including hydro, wind and geothermal backed by thermal peakers for security of supply. Electric vehicle uptake is relatively rapid after 2020. New energy sources are brought onstream in the late 2020s and 2030s, including biomass, marine, and carbon capture and storage. Demand-side response helps to manage peak demand.
South Island Surplus	Renewable development proceeds at a slightly more moderate pace, with all existing gas-fired power stations remaining in operation until after 2030, though taking a more mid-order role as gas prices increase. The coal-fired units at Huntly Power Station are shifted into a reserve role and eventually removed from service. Wind and hydro generation increase considerably, particularly in the lower South Island. Relatively little geothermal energy is utilised. Thermal peakers supplement renewable development.
Medium Renewables	A 'middle-of-the-road' scenario. Renewables are developed in both islands, with North Island geothermal development playing an important role. The coal-fired units at Huntly transition through dry-year reserve to total closure. Thermal peakers and a new CCGT supplement renewable development. Tiwai smelter is assumed to decommission in the mid-2020s.
Demand Side Participation	Demand-side participation becomes a more important feature of the market, driven by a desire from consumers of all types to become more involved. Electric vehicle uptake is high, and vehicle-to-grid technology is used to manage peaks and provide ancillary services. On the generation side, new coal- and lignite-fired plants are constructed after 2020, and geothermal resources are developed. Little new hydro can be consented, however, and some existing hydro schemes have to reduce their output (due to difficulty in securing water rights). Huntly Power Station remains in full operation until 2030. Electricity-sector emissions rise, though transport- sector emissions would be less than in other scenarios.
High Gas Discovery	Major new indigenous gas discoveries keep gas prices low to 2030 and beyond. Some existing thermal power stations are replaced by new, more efficient gas-fired plants. New CCGTs and gas-fired peakers are built to meet the country's power needs; the most cost-effective renewables are also developed. The demand side remains relatively uninvolved.

Assuming that an enduring characterisation of the grid can be made, the SOO scenarios may also be useful in determining the appropriate extent of the ‘tilt’. For example, the SOO scenarios could take a prominent role in the estimation of the transmission costs that would be avoided throughout the transmission network following various generator location decisions. For example, Transpower could re-run the market development scenarios to determine how, if at all, its forecast investment programme would change if generators located in the various regions throughout the stylised grid (as per the methodology described above). This could provide an initial indication of the locational prices that might be appropriate. The scenarios could then be re-tested with different ‘tilts’ to examine how they differ over time in order to arrive at appropriate locational prices.

Finally, assuming that an enduring structural topology based on the principal drivers of investment for a 10 to 20 year period can be determined, and an initial tilt implemented, the time will come when those locational prices may need to be adjusted. For example, a TPS methodology could be judged successful if in, say, 10 years time there had been additional generation in the upper North Island that had reduced northward load flows and the relative need for transmission reinforcement. It may be tempting to conclude that, in such circumstances, the extent of the tile could be reduced. However, this should not be presumed to be the case.

The basic reason for the tilt is that unless the LRMC of providing south to north transmission capacity is reflected in transmission charges, generators would prefer to locate in the south –

presumably because the relevant land, wind or hydro resource costs are more attractive in that location. For so long as it remains the case that the additional costs of locating new generation in the north are less than the avoided costs of providing new transmission capacity to facilitate northward power flow, then it would be appropriate for the tile to remain in place, with its extent determined by the future transmission consequences of new South Island-located generation.

Nevertheless, development of a TPS methodology would need to include a clearly specified process by which prices periodically are reviewed, including for example:

- the period for which the initial locational prices will apply – for the reasons outlined above, there is good reason for this to be in the order of 10 years, in line with investment decisions; and
- the way in which the 'tilt' will be recalculated – this may simply involve revisiting the simplified grid topology in light of developments in the interim and forecast investment needs at that time, and re-running the market development scenarios as described above.

In summary, the greatest potential ***strength*** of the TPS methodology – its simplicity – is also, ironically, its greatest potential weakness. If the challenges set out above – most notably the arriving at an enduring structural characterisation – cannot reasonably be met, then it becomes very difficult to derive reasonable LRMC forecasts, and the locational prices indicated by a TPS methodology will be unreliable.[111]

5.1.1.3. Summary

The TPS methodology represents a *conceptually* sound but relatively straightforward way of providing appropriate locational signals to generators through the interconnection charge. Its key potential strength is that it relies upon a simple formula-based approach rather the periodic application of complex modelling of load flows, which would introduce undesirable volatility and uncertainty into prices. However, this potential strength is also its greatest potential weakness. In particular, the methodology is contingent upon arriving at a simplified, enduring grid topology (ie, for at least 10 to 20 years) and, to the extent this is not possible, then the methodology quickly becomes very difficult (if not implausible) to implement.

In the context of the New Zealand transmission grid, will need to come to a view on whether it is reasonable to assume that it is the need to maintain and upgrade a 'structural northwards flow' that is the ***principal driver*** of the investments summarised in Figure 5.1. If that characterisation is incorrect, or debatable, then the generalised TPS methodology set out above will be fraught with controversy, since it will be dependent on subjective judgements regarding the purpose of particular transmission investments and thus the potential for such investments to be avoided. There are also a number of other potential drawbacks with the methodology, including:

- while being relatively simple, it is nevertheless more complex than the existing interconnection charging arrangements;

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[111] There was a diverse range of views amongst the Working Group regarding whether such a structural representation was appropriate.

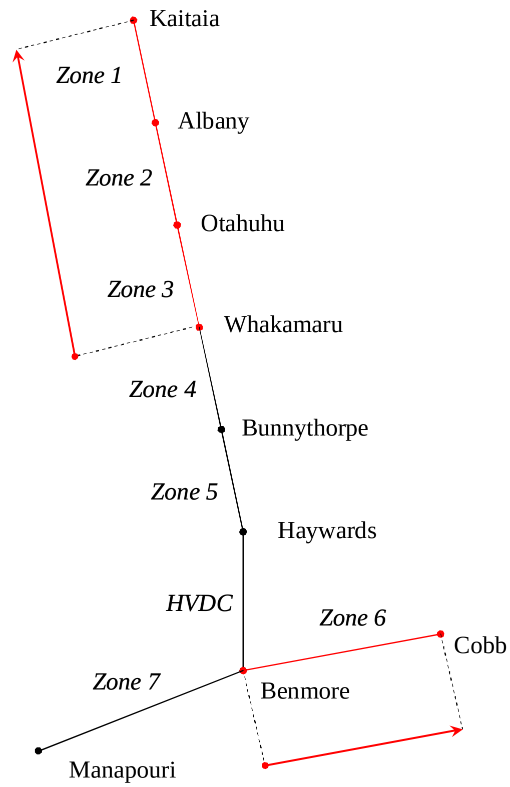
- levying interconnection charges on generators would be a significant departure from the existing arrangements; and
- it would have some cost-shifting implications between market participants.

If arriving at an enduring, simplified structural characterisation of the grid based on the principal drivers of investment is not feasible, or the potential drawbacks of a generalised TPS methodology are thought to outweigh the potential advantages, an alternative is to focus *more narrowly* upon those locations where the drivers of transmission investment are unambiguous and/or where the investment that is required over the next 10 years or so is reasonably clear. We consider this alternative approach in the following section.

5.1.2. Bespoke Locational Preferences

An alternative to the *generalised* TPS methodology described in the previous section is to focus *more narrowly* upon those locations where the drivers of transmission investment are unambiguous and/or where the location of the generation investment that is desired over the medium-term is reasonably clear. In this way, it may be possible to design a suite of locational price signals based upon *bespoke locational preferences*. For example, the 'generalised' TPS methodology described above hinged upon an assumed 'structural northwards flow'. However, as we noted, it may simply not be possible to make such a strong simplifying assumption.

Having said that, it *may* be plausible to identify locations throughout the grid where the direction of load flows and drivers of investment are reasonably clear, and are likely to remain so over the longer-term. To the extent that such locations can be identified, it may be possible to ascertain more readily the types of generation investment that locational prices might be designed to encourage (or discourage, as the case may be), and to target such signals accordingly.



For example, we understand that the direction of flows across zones 1, 2 and 3, and within zone 6 of our stylised grid topology are unambiguous – they are virtually always south to north (see the figure adjacent). Outside of these locations, power flows in both directions and so it is difficult to infer an enduring 'structural flow'. Put another way, it may be difficult to ascertain with any accuracy the principal drivers of investment or, importantly, the proportion of transmission costs that would be *avoided* in these regions by various generation location decisions. In such circumstances it may be difficult to determine what the appropriate locational price signal should be.

In addition to a conclusion about the nature of the flows, it *might* also be feasible to infer that the transmission investment scheduled to be undertaken in those regions (ie, the upper north island (zones 1 to 3) and the upper south island (zone 6)) is motivated significantly by a desire to facilitate northwards flow. For example, it seems very likely that the $1.2b NIGUP investment set out in Figure 5.1 is to allow northward flows north of Whakamaru. In other words, additional generation investment in these regions – and particularly in the ***north*** of these regions – may avoid or defer some or all of this forecast transmission investment.

In other words, it may be possible to implement a ***more targeted*** location price signal through the interconnection charge that is designed to encourage additional generation investment in these locations. One approach would be likely to involve dividing the grid into four regions, ie, the upper North Island ('UNI', comprising zones 1, 2 and 3), the upper South Island ('USI', comprising zone 6), the lower North Island ('LNI', comprising zones 4 and 5) and the lower South Island ('LSI', comprising zone 7). The idea would be to set *lower* interconnection prices for generators that in the UNI and USI regions, and perhaps also for prices to vary ***within*** those regions, depending upon where in those regions additional generation will be of most benefit.

Such an approach would amount to a modified version of the generalised TPS methodology described in the previous section. For example, locational price signals might be broadly estimated as follows (note the similarity to the generalised methodology):

- determine the net present value (NPV) of the forward-looking investments required to update/expand the 'main trunk' over the next decade or two in the UNI and USI, and determine the revenue ($/MW/Year) required to support this investment;
- for each *zone* within the UNI and USI regions, estimate the quantum of forecast annual transmission costs that would be avoided throughout the whole *region* if a generator of a capacity equivalent the additional transmission capacity needed in that zone located immediately above (north) of that zone;
- assuming a general south-north flow within the UNI and USI regions, progressively more of the costs set out in Figure 5.1 should be avoided the *further north* that a generator locates within each region, for example:
  - a 1000MW generator located at Kaitaia may avoid most or all of Transpower's forward-looking investment costs in the UNI, since it is the *northernmost* point in the UNI region;
  - a 1000MW generator located at Whakamaru may avoid very few if any of the forward looking investment costs in the UNI, since it is the *southernmost* point of the UNI region; and
  - a generator of any capacity locating anywhere in the LNI would not avoid any of the forward looking investment costs in the UNI.
- applying an analogous methodology to the preceding section, one would expect to arrive at the following pattern of interconnection prices in the North Island:
  - an interconnection price for generators that is $0/kW/Y in zone 1, and becomes more expensive in zones 2 and 3, respectively; and
  - an interconnection price for generators in the LNI (in zones 4 and 5) that is equal to (or perhaps greater than) the interconnection price in zone 3 (which should be the most expensive price), so as to provide a disincentive to locate plant in that region;

- it is likely to be necessary to divide zone 6 into two 'sub-zones' in order to implement the methodology in the South Island, in which case a similar pattern would be expected to emerge:
  - an interconnection price in the USI that is $0/kW/Y in zone 6, say, north of Islington, and becomes more expensive south of Islington; and
  - an interconnection price for generators in the LNI (in zone 7) that is equal to (or perhaps greater than) the interconnection price in zone 6 south of Islington, so as to provide a disincentive to locate plant in that region; and
- decisions regarding the charging parameter, the recovery of the residual interconnection revenue from load and the potential creation of an 'unders and overs' account would remain the same as for the generalised TPS methodology described above; and
- the period for which the bespoke locational price signals will apply, and the process by which those prices will be revisited and reset will also need to be clearly specified.

The advantage of such an approach over the generalised TPS methodology described in the previous section is that it is likely to reflect more accurately the LRMC of transmission due to the reduced ambiguity surrounding the assumed direction of flows, and so the principal drivers of forecast transmission investment. However, this comes at the expense of a loss of generality, and potentially the durability of the methodology over time, although if the process by which those bespoke prices will be reset is clearly specified beforehand, this is less important. A yet *more granulated* approach than the methodology described above would be to focus upon the ***generation investment that is desired over the shorter-term***. For example, at present, one might wish to provide incentives to generators to:

- locate thermal peaking plant in Auckland, rather than in Taranaki; and
- locate intermittent wind generation assets in the North Island rather than the South Island.

Such incentives might be created by employing a very similar approach to that described above. For example, one might attempt to identify those transmission investments required to transport power from Taranaki to Auckland, and charge generators in a defined 'Taranaki region' a higher interconnection price than generators elsewhere. A similar approach might be adopted for South Island generators vis-à-vis North Island generators with respect to investments required to support South Island wind farms (or, the existing HVDC charge might be considered to be fulfilling this role).

However, the fundamental problem with designing locational prices to address short-term investment requirements such as those listed above is ***durability***. Put simply, although it may be possible to design a locational price to signal the generation investments desired ***today***, in a few year's time a very different portfolio of investments might be needed, and that signal will no longer be appropriate. Indeed, the short-term locational signals that might have been considered to be needed as recently as five-years ago may bear little resemblance to the short-term signals desired today. In other words, such an approach is unlikely to meet one of the fundamental criteria in the problem definition, ie, to design a TPM that endures in line with the time frames for investment decisions, so as to provide certainty.

In summary, it may be feasible to modify the generalised TPS methodology described in the previous section so as to create locational price signals based upon ***bespoke locational*** *preferences*. In particular, it may be plausible to identify locations throughout the grid where the direction of load flows, and so the principal driver of investment is reasonably clear, and is likely to remain so over the longer-term. To the extent that such locations can be identified, it may be possible to ascertain more readily the types of generation investment that locational prices might be designed to encourage (or discourage, as the case may be), and to target such signals accordingly. However, a yet ***more granulated*** approach that focused upon the generation investment that is desired over the shorter-term is unlikely to be sustainable.

5.1.3. An Efficient Tax

If neither a generalised TPS methodology nor a more targeted methodology based upon bespoke locational preferences is considered to be feasible this would seem to lead to the conclusion that an enduring locational price signal cannot be sent by means of a TPS methodology. Most notably, if no enduring characterisation of the grid for a period of 10 to 20 years is possible – even in specific locations – then the process of estimating long-run costs and producing robust price signals is likely to become unworkable. In simple terms, it is unlikely to be feasible to provide a reliable locational price signal through the interconnection charge because it would not be possible to ascertain with sufficient certainty the nature of the signal that should be sent.

Locational signals will in these circumstances be limited to those provided through the operation of the nodal pricing and dynamic loss factor regimes, the deep connection charging arrangements and the application of the GIT (the ‘peak demand’ signal contained in the RCPD charge would also be retained). The principal function of the TPM insofar as the interconnection charge is concerned is simply to recover the required revenue in a way that entails the fewest distortions. In other words, the costs associated with grid upgrades would essentially be recovered by means of a ‘tax’ that would be designed to be as efficient as possible. This may involve continuing to levy the charge on load (this is less likely to result in changes in behaviour and would minimise regulatory costs since it is consistent with the status quo) and also incorporating the *HVDC charge*, or alternatively, the cost of the Pole 1 replacement, into interconnection charges.

Indeed, a corollary of being unable to come to an enduring characterisation of the grid – even in specific locations – is that it is presumably also not possible to ascertain the appropriate locational signals to send South Island generators in relation to *HVDC transmission*. For example, if one cannot confidently say that the principal purpose of the HVDC link (including the upgrade) is to facilitate northward power flows, then one cannot be confident that the current HVDC charge is an appropriate locational price signal to provide South Island generators. In particular, levying the charge ***as though*** the only purpose of the HVDC link is to facilitate south to north flow may lead to dynamic efficiency losses if the resulting charge is so high that, from a system-wide perspective, an efficient combination of South Island generation and transmission system development is foregone.

The design and application of the GIT would be particularly important in these circumstances. In consequence, it is likely to become all the more important to address the potential shortcomings in the way in which the test is presently applied that were introduced in section 4.4. In particular, if multiple transmission investments are intended principally to address the same problem - say, constraints in a particular importing region - then the interdependencies between these projects should be recognised in some way when undertaking the GIT. Indeed, as section 4.4 explained, introducing each project in isolation may bias the GIT towards transmission investments and away from alternatives such as generation.

For example, we understand that separate GIT processes were completed for the NIGUP (Whakamaru to Otahuhu) and NAaN (Otahuhu to Albany) transmission investments set out in Figure 5.1. If the principal purpose of both of these projects was to facilitate northward flows to Albany, and the alternative in each instance was, say, additional generation in Albany, then there ideally should have been a process for assessing the costs and benefits of the NIGUP and NAaN investments *collectively*. Assessing the projects collectively may have increased the chance of the NPV of additional generation outweighing the NPV of the suite of projects, when examining each project *separately* might reach the opposite conclusion.

5.1.4. Summary

On balance, it is unclear whether the nodal pricing arrangements, when combined with the application of the GIT and deep connection charging, will play a sufficiently prominent role in preventing sub-optimal locational decisions by generators and load.[112] Moreover, the locational signal provided by the HVDC charge is relatively blunt and, in particular, is incapable of providing ***intra-island*** locational signals. In other words, there may be scope for the TPM to be modified in some manner so as to provide superior locational signals – particularly to generators. The objective in doing so would be to entice behaviour that reduces or defers the future transmission expenditure that is needed, so as to improve the use of and investment in the grid, without creating other distortions that are even worse.

A generalised TPS methodology represents a *conceptually* sound but relatively straightforward way of providing appropriate locational signals to generators through the interconnection charge. Its key potential strength is that it relies upon a simple formula-based approach rather than complex periodic modelling of load flows, which would introduce undesirable volatility and uncertainty into prices. Ironically, this potential strength is also its greatest potential weakness. In particular, the methodology is contingent upon arriving at a simplified, enduring grid topology for a period in the vicinity of 10 to 20 years and, if this is not possible, then the methodology quickly becomes difficult (if not implausible) to implement.

An alternative is to modify the generalised TPS methodology so as to create locational price signals based upon *bespoke locational preferences*. For example, it may be plausible to identify locations where the direction of load flows is reasonably clear, and is likely to remain so over the longer-term. To the extent this is possible, it implies that the types of generation investment that locational prices might be designed to encourage (or discourage, as the case may be) can be ascertained and signals designed to encourage such outcomes. A yet ***more granulated*** approach would be to focus upon the generation investment that is desired over the ***shorter-term***. The key potential draw-back with these approaches is ensuring that the locational signals are ***sufficiently durable.***

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112 We noted in section 4.2 that Frontier and Covec have both previously argued that the locational signals in New Zealand from nodal pricing and the GIT, although not perfect, are ***adequate***. See: Frontier Economics, Transmission Pricing Methodology – Options and Guidelines, Final Draft Issues Paper, June 2004 and Covec, ***Locational Signals for New Investment,*** August 2004.

Finally, if it is simply not feasible to determine with sufficient confidence the locational signals that should be provided by means of the interconnection charge, then neither of the methodologies above can reasonably be implemented. The objective should then be to recover required interconnection revenue – including HDVC revenue, or the revenue related to the Pole 1 replacement – in the *least distortionary way possible.* In these circumstances, locational signals will be limited to those provided by nodal prices, deep connection charges (assuming they are retained) and the application of the GIT authorisation processes. The application of the GIT assumes even more prominence in these circumstances, and so addressing the potential weaknesses in that process become increasingly important. These high-level options are summarised in Table 5.

Table 3
Summary of High-Level Options for Introducing Locational Signals

Characterisation of Grid	TPM Option	Key Issues
Structural south-north flow that will drive new investment in that 'highway' over a 10 to 20 year period	§ TPS methodology applied to generators § Residual charge on load based on RCPD § Shallow connection (*) § No HVDC charge	Is the assumed structural characterisation valid?
'Bespoke' locational preferences, ie, focus on locations where load patterns are clear or on shorter-term investment requirements	§ 'Modified' TPS methodology applied to generators § Residual charge on load based on RCPD § Shallow connection (*) § No HVDC charge	Would the estimated locational signals be sufficiently enduring?
Enduring characterisation not possible	§ Retain deep connection (*) § No HVDC charge § Locational signals provided by nodal prices, deep connection and the GIT	Is there a feasible alternative to this 'default' position?

(*) See discussion in section 5.3 below.

It follows that the critical decision facing the Steering Group is whether it is feasible to come to a settled view on an enduring characterisation of the transmission grid, or a set of bespoke locational preferences. In our view, Transpower is likely to be in the best position to produce an enduring characterisation of the grid, eg, based on its 10-year plus transmission development plan and the SOO scenarios. Assuming that an enduring characterisation of the grid can be made, the SOO scenarios may also be useful in determining the appropriate extent of the 'tilt', and in any reset.

As Table 5 illustrates, if no enduring characterisation is possible – even in specific locations – then the process of estimating long-run costs and developing robust price signals is likely to become unworkable. In these circumstances, the costs associated with grid upgrades would then need to be recovered by means of a ‘tax’ that would be designed so as to be as efficient as possible.

5.2. Modify HVDC Charge

The analysis in the preceding sections suggests that the circumstances in which it may be appropriate to retain the HVDC charge in its current form are likely to be quite limited. Section 4.5.1 explained that the ‘beneficiaries pays’ principle that has historically formed the rationale for levying the charge on South Island generators does not form a sound basis for determining the incidence of the charge. Rather, any decision to retain the HVDC charge should be on the basis that it is the most efficient means of recovering the long-run investment costs associated with the HVDC link, ie, it does not cause inappropriate distortions, and it provides appropriate locational signals of those costs.

On this basis, in our view the justification for retaining the charge in its current form appears not to be strong. First, if some derivation of the TPS methodology described in section 5.1 is implemented, then there would *no longer be any need* for the HVDC charge since additional, superior locational signals would be provided elsewhere – including almost certainly to South Island generators. In particular, the generalised and bespoke TPS methodologies described above are capable of providing ***intra-island*** locational signals, which the HVDC charge cannot do. In other words, the TPS methodologies described in the previous sections have the potential to represent a superior alternative to the existing HVDC charge.

Second, if it is *not* possible to implement the TPS methodologies set out in section 5.1, then a corollary must be that one is unable to be confident that retaining the HVDC charge will provide an appropriate locational signal to South Island generators. For example, if it is not possible to come to an enduring characterisation of the grid – even in specific locations, it is unlikely to be possible to say that the principal purpose of the HVDC link is to facilitate northward power flows. In these circumstances, continuing to levy the charge *as though* the only purpose of the HVDC link is to facilitate south to north flow may result in charges that are too high. In particular, it may lead to dynamic efficiency losses if, from a system-wide perspective, an efficient combination of South Island generation and transmission system development is foregone.

In other words, our analysis suggests that either the HVDC charge could be replaced by a TPS methodology capable of delivering a superior locational signal or, if such a methodology cannot feasibly be implemented, then the same obstacles are likely to preclude one having any confidence in the existing locational signal being provided by the HVDC charge. Either way, the justification for retaining the HVDC charge does not appear to be strong. In particular, it suggests that the HVDC charge either should be incorporated entirely into the interconnection charge, or that the costs associated with the Pole 1 replacement should be incorporated. We describe this option below. However, for completeness, we have also considered scenarios in which the entire HVDC charge is retained as a separate charge, but is levied on a different basis, and in which the HVDC link becomes a merchant transmission link.

5.2.1. Incorporate HVDC Charge into Interconnection Charge

The first option is to incorporate the entire HVDC charge into the interconnection charge and to continue levying that charge on off-take customers. We note that such an approach may offer a number of the potential benefits, including:

- a reduced incentive for South Island generators to withhold peaking capacity in order to avoid HVDC charges (to the extent that this presently represents a material distortion, which we consider is quite unlikely – see Box 4.2);
- a reduced incentive for South Island generators to embed generation to 'hide behind load' in order to minimise HVDC charges in circumstances where transmission-connected generation would offer greater market benefits; and
- a reduction in the competitive disadvantage faced by new generators looking to invest in the South Island (or small generators looking to expand) as compared with the three existing generators, particularly Meridian (see Box 4.3).

Of course, it should be recognised that significant short-term wealth transfers are likely to eventuate from any such change if interconnection charges remain confined to off-take customers, most notably:

- South Island generators will receive a significant reduction in costs, since they will no longer have to pay HVDC charges and would not pay interconnection charges;
- off-take customers will be required to pay more transmission charges, since they would have to pay for the HVDC link in addition to the balance of the interconnected HVAC network; and
- because interconnection customers represent a 'cost pass-through' for distribution companies, and are likely also to be passed on by retailers, retail electricity prices are likely to increase in the short-term – albeit by only a very small amount (see below).

The potential for short-term price increases to retail customers and the potential for distortions to be made to consumption decisions represent potential drawbacks of levying the HVDC charge on all off-take customers. However, because transmission charges represent only a modest proportion of retail electricity prices (approximately 6 per cent on average), incorporating the HVDC link into charges for the interconnected AC network is likely to result in only a small increase in average retail prices. Specifically, current retail prices would be likely to increase by less than 1 per cent on average if the $80m HVDC charge was levied on off-take customers, as Box 5.1 illustrates. It seems unlikely that a price increase of this magnitude would bring about a material change in final consumption.[113]

[113] The calculation set out in Box 5.1 necessarily incorporates a number of assumptions. First, it should be noted that the estimated increase is in average prices, so individual customers' prices may increase by more or less than the average. The estimated effect on the HVDC charge of the pending Pole 1 replacement is also not included (if the charge was limited to North Island load, the price increase would be higher, but not substantially so). Assuming the upgrade increases HVDC charges to approximately $150-$160m per annum, and holding the other parameters constant, the increase in average retail prices is still likely to be less than 2 per cent. Finally, the calculation assumes that there would be no off-setting reduction in wholesale prices when, over the medium term, such offset is more likely to be the case.

Box 5.1
Estimated Effect of HVDC Charge on Average Prices

Total energy 2008 (kWh) (assuming 70:30 split between retail and industrial):

Retail: 26,388,478,496 kWh

Industrial: 11,309,347,927 kWh

Total: 37,697,826,423 kWh

Average tariff (c/kWh):

Retail (15 Aug 2008, inc distribution and transmission charges): 9.48c/kWh

Industrial (2008, inc transmission charges but not distribution charges): 29.54c/kWh

Total revenue:

Retail: $7,794,665,599 **=** (26,388,478,496 kWh x 9.48c/kWh) ÷ 100

Industrial: $1,072,040,408 **=** (11,309,347,927 kWh x 29.54c/kWh) ÷ 100

Total: $8,866,706,007 **=** $7,794,665,599 + $1,072,040,408

Average retail price (c/kWh): 23.52c/kWh = ($8,866,706,007 ÷ 37,697,826,423 kWh) x 100

HVAC interconnection charge (1 April 2008 – 31 March 2009): $508,563,000

HVDC charge (2009/10): $78,330,000

HVAC charge as a % of total revenue: 5.74% = ($508,563,000 ÷ $8,866,706,007) x 100

Assuming that the distinction between the HVDC link and the interconnected HVAC network was collapsed, the current HVAC charge would increase by the amount of the current HVDC charge. Assuming that 100% of the charge was passed through to retail prices, and that there was no off-setting reduction in wholesale prices (which one might expect, at least in the medium-term for the reasons set out above), average retail prices would be affected as follows:

New total revenue: $8,945,036,007 = $8,866,706,007 + $78,330,000

New average retail price (c/kWh): 23.73c/kWh = ($8,945,036,007 ÷ 37,697,826,423 kWh) x 100

Change in average retail prices: 0.89% = ([23.73c/kWh - 23.52c/kWh] ÷ 23.52c/kWh x 100

If sufficient concern remained over wealth effects, an alternative approach would be to phase out charges for existing HVDC assets over time, by incorporating a larger percentage of the cost of sunk HVDC assets within the interconnection charge each year, so that South Island generators pay a smaller ‘legacy’ charge each year. Table 6 provides a simple illustration. In this example we have assumed that the ‘legacy HVDC charge’ is $80m, and that ‘new HVDC charges’ are $70m to recover the cost of the replacement of Pole 1, resulting in a ‘total charge’ of $150m. For simplicity we have assumed that the $150m remains constant over the 10-year phase-out period, and we have ignored the effects of inflation.

Table 4
'Phase Out' of Legacy HVDC Charges

		Off-take Customers		
	'Legacy' HVDC Charges to SI Generators	'Legacy' HVDC Charges to Off-take Customers	'New' HVDC Charges	Annual Effect on HVAC Charges
Year 1 (100%:0%)	\$80m	\$0m	\$70m	\$70m
Year 2 (90%:10%)	\$72m	\$8m	\$70m	\$78m
Year 3 (80%:20%)	\$64m	\$16m	\$70m	\$86m
Year 4 (70%:30%)	\$56m	\$24m	\$70m	\$94m
Year 5 (60%:40%)	\$48m	\$32m	\$70m	\$102m
Year 6 (50%:50%)	\$40m	\$40m	\$70m	\$110m
Year 7 (40%:60%)	\$32m	\$48m	\$70m	\$118m
Year 8 (30%:70%)	\$24m	\$56m	\$70m	\$126m
Year 9 (20%:80%)	\$16m	\$64m	\$70m	\$134m
Year 10 (10%:90%)	\$8m	\$72m	\$70m	\$142m
Year 11 (0%:100%)	\$0m	\$80m	\$70m	\$150m

An alternative to levying the entire HVDC charge on off-take customers would be to make a distinction between *historic* HVDC charges and *future* charges. For example, the costs associated with future upgrades to HVDC assets could be incorporated into interconnection charges and paid for by load, with South Island generators continuing to pay for the existing 'sunk' HVDC assets. In this way, the wealth transfer effects would be reduced and South Island generators would be left only to pay for sunk assets, which should reduce the efficiency consequences.

If such an approach was favoured, it would require that a 'line in the sand' be drawn, such that the HVDC charge as at a particular date – and the allocation amongst South Island generators as at that date – was considered to be a 'legacy charge'. All subsequent investments in HVDC assets – most notably from the pending replacement of Pole 1 – would be included within the interconnection charge and paid for by load. In order to avoid 'gaming', the line in the sand should be drawn at some point in the recent past (eg, as at the conclusion of 2008), with future 'sunk' HVDC charges being based on South Island generators' HAMIs at that date. We note that the potential modifications to the *way* in which the HVDC charge is levied that are described below would be equally applicable to any continuing 'legacy' HVDC charge.

5.2.2. Retain the HVDC Charge, but Change Parameter

For the reasons set out above, there is unlikely to be strong case for retaining the HVDC charge in its current form. However, if the decision was made to retain the charge in its entirety there may still be reason to revisit the *way* in which the charge is levied. This applies equally to any 'legacy' HVDC charge. As section 4.5.2 explained, determining HVDC charges on the basis of South Island generator's historic peak injections (HAMI) is said by some South Island generators to distort their use of and investment in peaking capacity, specifically:

- *in principle*, the HAMI charging parameter provides incentives to withhold supply of peaking capacity;

- the incidence of the HVDC charge may reduce incentives to invest in the South Island (particularly in peaking capacity); and
- the HVDC charge increases the likelihood that new investment will be undertaken by incumbent South Island generators (most notably Meridian).

Whether the first two contentions are symptomatic of a material problem with the existing HAMI based charging parameter is unclear. Indeed, we explained in section 4.5.2 that the circumstances in which it will be profitable to withhold capacity from the market are likely to be relatively infrequent, and the disincentives to invest in the South Island are not necessarily a bad thing if North Island investment is preferable. In other words, we are not convinced that there is a pressing need to change the HAMI-based parameter. Nonetheless, if there was sufficient motivation to make a change, two alternatives are:

- an ***energy-based*** charge, whereby generators' HVDC charges are determined based on their annual $/MWh dispatch; and
- a ***capacity-based*** charge, whereby generators' HVDC charges are determined based on their ***registered, licensed, or nameplate capacity.***

The potential benefits from switching to an energy-based charge would include:[114]

- a reduced incentive for South Island generators to withhold peaking capacity in order to avoid HVDC charges (to the extent that this presently represents a material distortion, which it may not be – see Box 4.2);
- a reduced incentive to embed generation to 'hide behind load' in order to minimise HVDC charge in circumstances where transmission-connected generation would offer greater market benefits s; and
- an improved ability for the HVDC charging arrangements to recognise 'energy transfers'.

However, there is a significant drawback with an energy charge. By basing HVDC charges upon $/MWh dispatched, this increases the opportunity cost of generating, and may result in higher wholesale prices. To a South Island generator it is the economic equivalent of an additional variable cost, such as fuel. If a South Island generator's 'true' variable cost was $30/MWh,[115] and the HVDC charge added, say, $2/MWh, then it would never bid less than $32/MWh, which clearly is distortionary since the HVDC charge relates to the recovery of a fixed cost, ie, whenever the market price was between $30 and $32/MWh, dispatch would not be least cost. Indeed, this was the principal reason that Transpower opted to impose a peak charge to recover HVDC costs.[116] In our view, this disadvantage would substantially outweigh the potential advantages of an energy-based charge.

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[114] We recognise that moving to an energy charge does not address the asymmetric consequences of new investments made by incumbents as compared with new entrants. This distortion is likely only to be reduced by removing the HVDC charge entirely.

[115] Noting that, for South Island hydro plants, this will include an endogenously determined value of water.

[116] Transpower, HVDC Sunk Cost Recovery Pricing Methodology, 19 April 1999, p11.

The potential benefits from switching to a capacity-based charge, in which HVDC charges are based on, say, nameplate capacity, is that the charge should in no way affect the usage/bidding decisions of generators (unlike an energy-based charge).[117] For existing generation facilities, capacity will have already been established and, for new units, nameplate capacity will be established during commissioning. Such charges are reasonably commonplace internationally. The potential disadvantage of a capacity-based charge is that it does not address the incentives to eschew from investing in South Island capacity (particularly peaking capacity), although for the reasons explained above, this is not ***necessarily*** detrimental if North Island investment is to be preferred.

However, changing the charging parameter to a capacity- or an energy-based charge will not address the fact that new South-Island based generation investment is most likely to be undertaken by incumbent South Island generators – most notably Meridian. Ultimately, this problem arises from the fact that the HVDC is an ***annual allocation*** of a pre-determined revenue requirement. So long as this remains the case, Meridian will continue to have competitive advantage when it comes to new investments. In other words, a potential way to address this problem would be to move away from the current practice of determining individual businesses' HVDC charges on the basis of an allocation of an annual revenue requirement.[118]

In summary, if the decision is made to continue to levy the HVDC charge (including the costs associated with the Pole 1 upgrade) upon South Island generators in order to provide a locational signal, our preliminary view is that the most sensible alternative to a HAMI-based charge is a parameter based on a measure of capacity that is not dependent on usage, eg, nameplate capacity. A capacity-based HVDC charge would not distort generators' bidding decisions, retain locational price signals (assuming they are appropriate) to guide entry decisions. However, would for the reasons set out in section 4.5.2, we are not convinced that there are any fundamental deficiencies in the HAMI-based charging parameter, in which case there is no pressing need to change.

5.2.3. Merchant HVDC Transmission Investment

A potential alternative proposed by some parties is for Transpower to be made to sell the HVDC link to a third party that can then operate it as a ***merchant transmission investment*** and

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[117] We recognise that moving to an energy charge does not address the asymmetric consequences of new investments made by incumbents as compared with new entrants. This distortion is likely only to be reduced by removing the HVDC charge entirely.

[118] An alternative might involve determining HVDC charges on the basis of a price that was set for a defined period of time (say, five years), and indexed each year. Under this option, in the event that new South Island generation capacity was connected, there would not be any immediate change in the allocation of HVDC charges to all existing South Island generators. Rather, that reduction would be delayed until the end of the fixed period. This would involve a significant departure from the fundamentally allocative exercise presently set out in the TPM. However, the difference between the sum of HVDC charges collected, and the HVDC revenue requirement (during the period of the fixed price) could be added to (subtracted from) the HVAC revenue requirement. The potential benefit of such a reform would be that it would ***reduce*** the current competitive advantage of incumbent South Island generators (most notably Meridian). However, it would not ***eliminate*** that advantage, because once the fixed price was reset so as to realign it with the HVDC revenue requirement, incumbent generators would stand to benefit from that normalisation process. Moreover, it would represent a significant departure from the allocation-based methodology presently contained in the TPM, and so would involve an element of regulatory uncertainty and implementation costs.

retain any constraint rentals that arise.[119] In other words, one could replace the existing ***regulated*** HVDC charging arrangements in the TPM with a ***market-based*** arrangement. However, for the reasons set out in section 2.2, the problem with such an approach is that the annual rentals that a prospective purchaser would anticipate recovering from the link would be unlikely to cover the annual costs of financing the asset. This would lead to one of two outcomes, either:

- no party would be prepared to make such an investment; or
- a party would only be prepared to make such an investment if it was permitted to constrain HVDC capacity so as to increase its rental income.

The second scenario above is problematic because, unlike generation capacity, absent physical capacity constraints, the short-run marginal cost of HVDC transmission is zero. In other words, to earn an acceptable rate of return, a merchant transmission investor would effectively have to place a 'tax' on generator offers, which would give rise to inefficient dispatch outcomes. In consequence, an alternative that involved merchant HVDC transmission investment may be worse than the current arrangements. For this reason, we do not consider that this is an option worth pursuing further.

5.2.4. Summary

The justification for retaining the HVDC charge does not appear to be strong. Specifically, there appears to be good reasons to replace the charge with a TPS methodology capable of delivering a superior locational signal. Alternatively, if a TPS methodology cannot feasibly be implemented, then the same obstacles are likely to preclude one having any confidence in the locational signal being provided by the current HVDC charge, suggesting that it should be removed. In other words:

- if a TPS methodology is implemented, the HVDC charge should be incorporated entirely into the interconnection charge and recovered by generators and load in the manner described in section 5.1.1 or 5.1.2; and
- if a TPS methodology is ***not*** implemented the HVDC charge should be either:
  - incorporated entirely into the interconnection charge and recovered from load; or
  - the costs associated with the Pole 1 replacement should be incorporated into the interconnection charge and recovered from load, with the remainder being recovered from South Island generators as a 'legacy charge'.

If some form of HVDC charge remains nonetheless (either the charge as presently formulated, or a 'legacy' charge), the most sensible alternative to a HAMI-based charge is a parameter based on a measure of capacity that is not dependent on usage, eg, nameplate capacity. However, we are not convinced that there are any fundamental problems with the HAMI-based charging parameter that might necessitate such a change.

[119] See for example: NZIER, *Proposed Guidelines for Transpower's Pricing Methodology: Comments on the Electricity Commission's Proposals,* November 2004. Appended to MEUG's submission to the Electricity Commission.

5.3. Modify Connection Charging Approach

The current 'deep connection' charging approach has the potential benefit of attributing as much of the 'blame' for connection costs as possible, which provides a locational signal to new generators and means that fewer costs need to be socialised and recovered through interconnection charges. However, the existing arrangements do create some anomalies. In particular, they have the potential to distort the investment decisions of generators, since their connection charges can vary substantially depending upon where they build, what type of generation they build, and the other parties that they 'share' connection assets with over time.

The key question is whether an ***alternative delineation*** would represent a material improvement. One alternative would be to introduce 'shallower' connection charges, where only directly attributable costs that we are 'sure about' are allocated to individual connecting customers. Below we explore the possibility of introducing a shallow connection charging regime or a 'but for' test for determining connection charges, as well as less extensive reforms, including changes to the way in which deep connection charges are levied, and potential modifications to the GIT.[120]

5.3.1. Introduce 'Shallower' Connection

An alternative to the deep connection charging arrangements is a shallower connection charging regime. Shallow connection charges have the advantage that they are less contentious, but have the potential disadvantage that they cause more costs to be socialised. There are myriad ways in which shallower connection charges could be implemented, but two potential alternatives (that are not mutually exclusive) are:

§ to delineate connection and interconnection assets by means of a 'technical' standard, rather than on the basis of identifiable beneficiaries; and/or

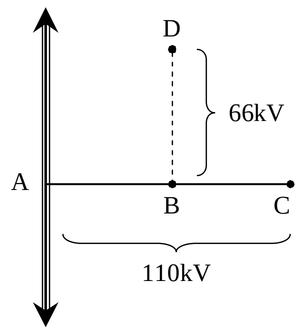
§ to allocate to parties only those costs that can be attributed directly to their decision to connect in that location, ie, they would not incur any 'shared' connection costs.

Consider the following simple grid configuration. Under the first option above, it might be decided that all transmission links that are, say, 110kV and above are interconnection assets, the costs of which are to be socialised (currently across all off-take customers). In these circumstances, customers seeking to connect at locations C and D might face the following connection charges:

§ the customer locating at C may pay charges for capital recovery on the new switchyard equipment at the GXP, and the associated operating and maintenance costs, but the costs of the 110kV line would be recovered via the interconnection charge; and

[120] We do not explore the possibility of connection charges being further 'deepened', eg, by seeking to charge connecting parties for consequential upgrades to the interconnected network. As explained in footnote 70, although it may be the case that further into the network there are other lines that are built with the generator in mind, proving *why* a line is built or who benefits from it is likely to be a highly contentious process. It is likely to be very difficult to create a simple and transparent rule-based means of determining these types of deep connection charges, and so we do not explore this option. See: H. Fraser, 'Can FERC's Standard Market Design Work in Large RTOs?', *Electricity Journal*, Volume 15, Number 6, July 2002 , p27.

§ a customer that locates subsequently at D may pay charges for capital recovery on the new switchyard equipment at the GXP, a share of the associated non capital costs, and the costs associated with the 66kV line, which would not be considered to be an interconnection asset.[121]



Now consider the second option set out above. Specifically, suppose that there is no technical delineation between interconnection and connection assets, but that a customer's connection charge comprises only those costs that can be attributed directly to its decision to connect in that location, and so do not incur any 'shared' connection costs. In these circumstances, customers seeking to connect at locations C and D might face the following connection charges:

§ the customer locating at C may pay new investment charges for capital recovery on the new A ð C link, and the switchyard equipment at the GXP, and the associated non-capital costs; and

§ the customer locating at D may pay new investment charges for capital recovery on the new D ð B link, and the switchyard equipment at the GXP, and the associated non-capital costs, but it would not be allocated a share of the connection charges associated with the B ð A link, which already existed.

Each of the alternatives described above (upon which there could by myriad variations) may be easier to conceptualise and provide for more stable and predictable charges than the existing deep connection approach. They may also reduce (but perhaps not eliminate entirely) the extent to which connection charges are not 'competitively neutral' across different generation investment options, and go some way to addressing the various connection pricing anomalies described in section 4.3.1. However, both options – and variants thereof – would also present a number of potential disadvantages, including:

§ shallow connection charges result in a greater proportion of costs associated with new connection being 'socialised', rather than being recovered from connecting parties;

§ shallow connection is likely to expand the application of the GIT, since more new assets are likely to be classified as interconnection assets, eg, under the first option set out above, lengthy transmission lines built to connect remote generators would be required to pass

[121] A potential variation would be to allow lower capacity lines to be categorised as interconnection assets if the investment passes the economic limb of the GIT.

the GIT (although, whether this is in fact detrimental is debatable, since it would seem to eliminate any 'first mover' problems that might exist);

- they may reduce to a significant extent the locational incentives for new generators (and to a lesser extent load), since they will not have to trade off to the same extent the additional costs of locating at various points with the additional costs of connection;
- a potential weakness with the first option is that any technical delineation based on voltage levels, or other grid characteristics may be seen as arbitrary and may create other unintended distortions that are worse than those described in section 4.3.1; and
- a potential disadvantage with the second option is that although it reduces the incentives for 'second- and third-movers' to locate so as to avoid having to pay 'shared' connection costs, it may compound the 'first-mover' problems described in section 4.3.2.

In our view, any shift to shallow connection charges – particularly with a delineation based upon a technical standard – would be more easily justified if further locational pricing signals were to be implemented through the interconnection charge. For example, if some variation of the TPS methodology described in the previous section was implemented, then the locational signal provided by the deep connection charging arrangements would become less important, since further explicit signals would be provided elsewhere. We note also that the immediate wealth transfer implications of a shift to shallow connection charges may not be all that significant.

As section 3.1.1 explained, on the basis of Transpower's 2009 revenue requirement, a switch from deep to shallow connection (ie, if all 'deep' or 'shared' connection assets were reclassified as shallow connection assets) would involve recovering approximately an additional \$21m per annum in interconnection revenue (and \$21m less in connection revenue), approximately 4 per cent of total HVAC revenue (which was \$540m in 2009). In other words, a switch from deep to shallow connection would not involve a ***substantial*** shift in the incidence of the HVAC revenue requirement between connection charges and interconnection charges.

Rather, as noted above, the more significant ongoing consequence of such as shift would be the likely expansion in the application of the GIT. Because more assets will be classified as interconnection, then the test will be applied more broadly and more often. For example, if a technical delineation is adopted, then lengthy transmission lines built to connect remote generators would be required to pass the GIT. On the one hand, this adds an additional layer of regulatory complexity. However, on the other hand, it would eliminate any 'first mover' problems potentially arising from the current connection charging arrangements, as described in section 4.3.2.

A further potential means of avoiding the connection pricing anomalies arising from the existing TPM is to introduce a 'but for' test for *new* connection investments. Under such an approach, when a generator or particular load (or loads) can be identified as the 'causer' or 'user' of an investment, the charges relating to the assets that would not be necessary 'but for' that party or parties are charged to them. In principle, such an approach would go some way to avoiding scenarios such as that arising in relation to the Gumfields development summarised in Box 4.1, since a new entrant generator could not be said to cause the shared connection costs that it currently would be allocated under the TPM to be incurred, ie, *but for* the generator connecting, those costs would *still* be incurred.

However, despite its 'in principle' appeal, there are a number of important practical considerations that may weigh against the implementation of a 'but for' test. The EC recently summarised many of the issues that would need to be overcome before such an approach was practicable, including:[122]

- despite the ostensibly objective standard, the allocation of the costs of a particular new investment to specific users may be complex, and is likely to be prone to controversy; and
- the methodology would require an acceptable test to differentiate between new assets and other capital expenditure in the grid, which may or may not include replacement and refurbishment expenditure.

Moreover, any derivation of the 'but for' approach that involved the introduction of FTRs would need to overcome all of the implementation challenges described in Appendix D. In consequence, the introduction of a 'but for' approach would be likely to involve high transaction costs in respect of its initial implementation and administration, as well as greater complexity and, potentially, controversy amongst market participants. In other words, the 'in principle' appeal of such a methodology may be more than outweighed by the practical considerations involved in its design, implementation and administration.

Ultimately, there is no easy solution to the question of deep versus shallow charges, as Fraser (2002) highlights.[123] No matter where the boundary is drawn, incentives will be created to change behaviour in order to avoid paying additional charges. There is no clearly-defined 'best' place to be along the spectrum from deep to shallow pricing, and any substantial change from the status quo is likely to involve its own disadvantages, a degree of regulatory instability, and unpredictable consequences. For this reason, we cannot be confident that a substantial departure from the existing deep connection charging arrangements to implement, say, shallower connection charges or a 'but for test', would deliver a material improvement upon the status quo. However, any shift to shallow connection charges would be more easily justified if further locational pricing signals were to be implemented through the interconnection charge.

5.3.2. Retain Deep Connection, but with Modifications

If the decision is taken to *not* shift to shallow connection charges, it is possible that more modest reforms may be capable of addressing at least some of the more significant distortions that potentially are created by the existing deep connection charging arrangements, without fundamentally altering those arrangements. We examine a number of possibilities below.

5.3.2.1. Seek Competitive Neutrality for Embedded Generation

Under the DGRs, embedded generators are required to compensate the distributor for the costs associated with its connection to the distribution network. However, the 'quid pro quo' is that the distributor must also pay the embedded generator a sum reflecting the costs that it *avoids* by it embedding there, eg, through any consequential reduction in its average RCPD,

[122] Electricity Commission, Transmission pricing methodology, Final decision paper, 7 June 2007, p14.

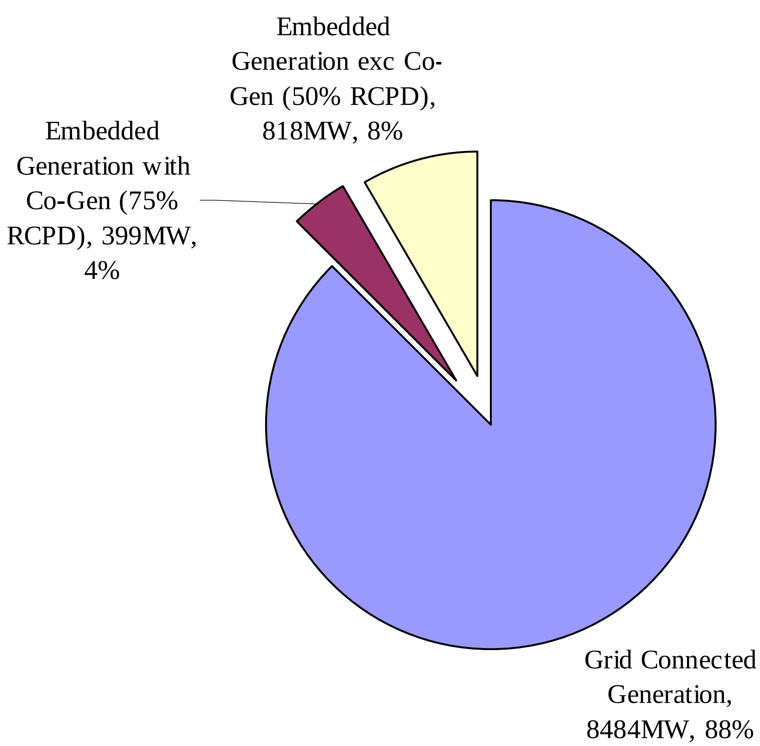
[123] H. Fraser, 'Transmission Business Model', in *Making Competition Work in Electricity*, ed, S. Hunt, New York, Wiley, 2002, p199.

and so its transmission charges. On the face of it, this would seem to provide rather strong incentives for embedded generation, since:

- although the distributor must pay compensation to an embedded generator that it would not have to pay to, say, a transmission-connected generator, that sum represents the *allocated* costs that it avoids by the generator connecting to its network, rather than the long run *marginal* costs that Transpower avoids because of that generator location decision; and
- from the perspective of the embedded generator, it receives a potential revenue stream that it would not if it was to connect to the transmission network, which provides it with a clear incentive to connect to the distribution network instead.

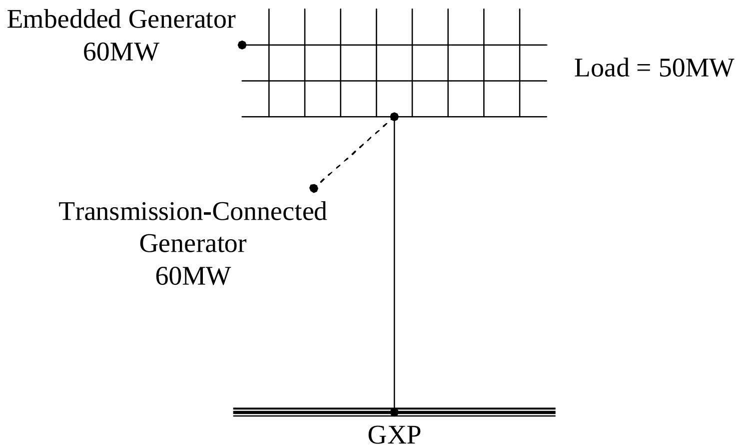
Contact Energy has estimated that the value of embedding vis-à-vis connecting to the transmission grid is approximately \$8.10/MWh in the North Island and \$10.60/MWh in the South Island.[124] This incentive appears to have had an effect. Indeed, there are significant volumes of embedded generation in New Zealand. Specifically, approximately 12 per cent of New Zealand's total installed generation is currently classified as embedded generation. Of that 12 per cent, less than half is attached to specific industrial loads, as Chart 4 illustrates.

Chart 4
New Zealand Total Installed Generation, MW



[124] This calculation is based on the current value of the avoided HAMI, which will vary by participant and the overall effectiveness of each station to off-set peak charges. See: Contact Energy, ***Transmission Pricing Project, Comments on Options Paper,*** 6 August 2009, p5.

However, it is not necessarily a good thing if the incentive to embed is *too strong*. In particular, an automatic payment of avoided transmission charges to embedded generators, but not to similarly located transmission-connected generators (most notably, peaking plant), risks distorting inappropriately the point at which generators choose to connect. This incentive is compounded by the fact that transmission-connected generators are likely to be liable for a significantly greater proportion of 'shared' connection costs, since embedded generators are only responsible for net injections into the transmission grid. Consider the simple grid configuration below.



Suppose that a generator was considering whether to build a 60MW transmission-connected peaking plant (to predominantly serve the local 50MW load), or to connect directly to the distribution network. If the generator connected to the transmission network, and Transpower built the necessary assets:

- it would be charged injection overheads associated with the new equipment required at the relevant GXPs; and
- it would pick up 55 per cent of the annual 'shared' connection costs (capital and overhead costs) associated with the connection link (ie, 60 ÷ [60 + 50]), based on its AMI.[125]

Note that the transmission-connected generator must pay for 55 per cent of the costs associated with the existing link despite the fact that it is unlikely ever to export 60MW along the connection link. Indeed, a proportion of its output is likely always to be taken by the local load. In contrast, if the generator connected to the transmission network:

- it would need to compensate the distributor for the costs associated with its connection to the distribution network;
- it would only pay a share of the connection costs (capital and overhead costs) associated with the connection link if it injected power into the transmission grid, ie, in the event that that local load did not account for all of its capacity and its AMI was positive; and

[125] Note that this is despite the fact that it is unlikely ever to export 60MW along the connection link, ie, a proportion of Gumfields' output is likely to always be taken by the local load.

- it would receive a payment from the distributor reflecting the costs that it avoids by the generator connecting to the distribution network, eg, through any consequential reduction in its average RCPD, and so its transmission charges.

When faced with these alternatives, there is a clear incentive to embed generation. This is in spite of the fact that the two options are likely to offer largely analogous costs and benefits, including equivalent 'net injections' at the GXP. In some circumstances, Transpower's prudent discount policy can address the problem by calculating a customer's interconnection charge ***as if*** a generator were embedded, thereby allowing it to remain grid-connected. However, section 3.2.5 explained that this policy is only available to ***existing generators*** considering embedding. Proposals to construct ***new*** embedded generation are not eligible for such discounts, so the policy represents only a ***partial*** solution.

Indeed, we have been provided with a number of examples of generators that have either made the choice to embed, or are giving it serious consideration for upcoming investments. In our view, this potentially gives rise to a competitive neutrality problem that may warrant reform to the existing arrangements. There are at least two potential ways in which to 'level the playing field':

- the DGRs could be modified so as to remove the requirement upon distributors to compensate embedded generators for avoided transmission costs;[126] and
- both embedded and transmission-connected generators could be allocated 'shared' connection costs based on their AMI injections at the GXP, ie, in the example above, this may be significantly less than 60MW for the transmission-connected generator.

For the first option listed above, we noted that Contact Energy has estimated that if all existing embedded generators were treated in the same way as transmission-connected generators, then there would be an 11.1 per cent reduction in interconnection charges to load (and a \$52m reduction in the avoided transmission charges that would otherwise have been paid to embedded generators). If ***only co-generation sites*** were treated as embedded generators, then a 6.6 per cent reduction in interconnection charges would eventuate (and a \$29m reduction in avoided transmission charges).

Both of the reforms might be expected to enable the two forms of generation to compete on a more even basis, and to reduce distortions to investment incentives. In other words, they offer potentially significant competitive neutrality benefits. Moreover, the potential costs of implementation are unlikely to be prohibitive. However, this view is not shared by all members of the Working Group, some of whom are of the opinion that there is nothing significantly wrong with the existing arrangements, and that the TPM is not an appropriate means to address any perceived shortcomings. For these reasons, although these issues may be worthy of further exploration at some stage in the future, we do not examine them further in this paper.

Finally, one feature of the existing arrangements pertaining to embedded generators that arguably ***should*** be changed is the way in which assets under common ownership are

[126] The alternative would be to put in place other mechanisms such as network support payments to allow transmission-connected generators (and potentially other non-network alternatives) to receive equivalent payments.

aggregated by Transpower for the purpose of calculating interconnection charges. As section 3.3 and Figure 3.2 explained, when Transpower determines the assets at the GXP, it aggregates all of the meters on both sides of the 110kV and 33kV Bus *by owner*. This creates an unusual asymmetry whereby the classification of a generator is potentially determined on the basis of whom owns the line connecting it to the GXP. The solution to this potential distortion is straightforward. Specifically, previously Transpower calculated interconnection charges separately for the 110kV and 33kV Bus. A reversion to such an approach would address any potential incentive problem arising from the current practice.

5.3.2.2. Reduce Asymmetric Consequences of 'Ownership'

The quantum of deep connection charges likewise depends upon the 'ownership' arrangements for new connection assets. Charges can vary depending upon whether the generator enters into a NIC, in which case Transpower will build the necessary connection assets that become 'open access' thereafter, or whether it builds the assets itself or enters into an arrangement for a distributor to do so.[127] As sections 4.3.1 and 4.3.2 explained, this not only causes potential asymmetries in connection charges, but may also pose other problems relating to the potential acquisition and exercise of market power.

Generators that become proprietors of new connection assets such as lengthy spur lines may not have a strong incentive to provide access to other generators subsequently wishing to connect their plants in the same location – even if those generators are willing to pay for any upgrades required or other forms of compensation. Indeed, on one view they have an incentive to refuse access to new generators since they are prospective competitors. Moreover, by controlling the transmission link, that generator may be able to exercise significant influence over local nodal prices. A similar scenario conceivably could eventuate by means of contractual arrangements with a distributor that builds a link for a generator.

We recognise that there may be legitimate motivations for undertaking such investments, including risk mitigation to avoid 'first mover' problems (see section 4.3.2) and speeding up the construction process. However, it is possible that the potential problems created by such investment may outweigh these types of considerations. In our view, there is a potential case to be made for revisiting the rules relating to generators (and distributors) constructing, and assuming ownership of transmission links. Potential reform options might include:

- generators being prevented from owning connection assets (or entering into analogous contractual arrangements with distribution companies), ie, all connection assets ultimately being owned and operated by Transpower, which could involve:
    - placing restrictions on generators and/or distributors constructing transmission links in the first place, ie, requiring all investments to be made under NICs; or
    - allowing generators and/or distributors to construct transmission links, but requiring them to sell those assets to Transpower upon completion;
- putting in place formal arrangements in the TPM (and/or NICs) to require 'first-movers' to be compensated by 'second- and third-movers' that connect subsequently to assets that have been funded by the first mover for a period, rather than relying upon the capital

[127] Or enters into a separate contractual arrangement for the construction of connection assets, eg, with a distributor.

sharing arrangements in the TPM (which are unlikely fully to compensate the first-mover) and leaving further compensation to be determined through commercial negotiation (and potentially creating the 'first mover' problems described in section 4.3.2).

Such reforms would serve to reduce the extent to which connection charges vary between connection options and locations, and therefore reduce the potential distortions to investment incentives. Moreover, formalising compensation arrangements should (in addition to the potential reforms for the GIT described below) might reduce the incidence of 'first-mover' problems described in section 4.3.2. However, there is not a consensus among the Working Group regarding the materiality of these issues. In particular, several members are of the opinion that the existing arrangements, based upon private negotiations, work well, and so there is no need to modify the existing arrangements. For these reasons, we consider that although these are options that may be worthy of further consideration at some stage in the future, we do not consider them further in this paper.

5.3.2.3. Revisit the Application of the GIT

It may be possible at least partially to address some of the connection pricing anomalies described in section 4.2 by revisiting the manner in which the GIT is applied. Section 3.2.2 explained that clause 40.2 of the Benchmark Agreement that investments in new connection assets should comply with the 'economic' limb of the GIT. However, we understand that in practice where both the connecting party and Transpower are in agreement that the investment should be made, the economic benefits are 'taken as read' and the formal cost-benefit analysis envisaged by the GIT is *not* undertaken. In our view, it may be beneficial to reform the application of the GIT to connection assets in two ways:

§ through Transpower requiring parties to connect at the most sensible location from an overall system perspective, where more than one location is technically possible, ie, by exercising the discretion provided by clause 40.2 of the Benchmark Agreement; and

§ allowing, in certain circumstances, for a new connection investment to be considered part of the interconnected network if the economic limb of the GIT is met, and socialising the attendant costs across multiple grid users (presently, all off-take customers).

The first option is not strictly a reform, since Transpower already is afforded the discretion to apply the economic limb of the GIT to customer-funded connection investments. Moreover, it is unlikely to represent a substantial departure from the current practice, which involves the economic benefits being 'taken as read' in the majority of cases. Rather, there may simply be certain circumstances where there are demonstrably superior alternatives to a proposed connection investment from an overall system perspective, in which case Transpower arguably should exercise the power afforded it by clause 40.2 of the Benchmark Agreement. The connection pricing anomaly that arises in relation to the Bromley and Islington GXPs is potentially illustrative.

Currently, the TPM treats GXP at Islington as an interconnection asset and the GXP at Bromley as a connection asset. Orion is therefore required to pay for 100 per cent of any upgrades at Bromley, and only approximately 10 per cent of any upgrade at Islington. However, the sensible engineering approach is to undertake investment at Bromley to reduce single asset dependency at Islington, and thus major failure scenarios. In consequence, if

Orion requested Transpower to upgrade the Islington GXP, there should (at least in principle) be scope within the GIT to address this problem, namely:

- any upgrade at upgrade at Islington arguably should be assessed against the alternative of investing at Bromley; and
- if the latter is more likely to minimise net market costs (for reliability upgrades) or maximise net market benefits (for economic investments) then an upgrade at Islington should not pass the GIT.

An equivalent process could be undertaken through Transpower in any other circumstances in which an alternative connection location (or investment option) is technically possible, and likely to be superior from an overall system perspective. As noted above, circumstances in which Transpower might wish to exercise this discretion are likely to arise relatively infrequently (eg, we understand that the Islington/Bromley GXP example is a rare occurrence in the New Zealand system), but it should perhaps be more willing to do so when there are foreseeable benefits.

The second potential reform is targeted once more at addressing the potential ‘first mover’ problems described in section 4.3.2 (to the extent they were considered to be material). Specifically, as 4.4 explained, there is presently no scope for the costs associated with ‘nationally significant’ or otherwise beneficial investments to be socialised if such investments pass the economic limb of the GIT. In particular, there presently is no scope for the GIT to be applied in such a way that ‘large connection investments’ (eg, to serve a new generation location), would be incorporated into the interconnected network and paid for by multiple users in the event that the GIT was passed (noting that a move to shallow connection pricing ***would*** result in the socialisation of such costs, as section 5.3.1 explained).

Rather, the resulting costs nonetheless would be imposed upon the connecting parties, whom may consequently not be prepared to outlay the deep connection charge. An alternative approach might be to:

- apply the GIT to all connection investments that meet certain criterion, for example:
  - the investment is above a certain monetary threshold so as to limit the application of the GIT to ‘large’ connection investments; and/or
  - the investment relates to investments likely to be of national significance, eg, spur lines to connect new generation locations; and
- if the investment passes the GIT, the assets are then classified as ‘interconnection’ assets and paid for through the interconnection charge, rather than via deep connection charges.

In summary, the reforms described above may go some way to addressing some of the connection pricing anomalies described in section 4.2, and the consequential distortions to investment incentives. For this reason, we consider that they are options worthy of further exploration in the subsequent project phase. However, it should be noted that the second option described above should only be implemented if deep connection charges are retained, since any move to shallow charges would produce the same outcome.

5.3.3. Summary

We cannot be confident that a *substantial* departure from the existing deep connection charging arrangements to implement, say, shallower connection charges or a 'but for' test, would deliver a material improvement upon the status quo. There are likely to be some advantages, but the potential disadvantages may be even greater. We note that the case for any shift to shallow connection charges is likely to be stronger if further locational pricing signals were to be implemented through the interconnection charge, as implied by the high-level options summarised in Table 5 in section 5.1.4.

It is possible that more modest reforms may be capable of addressing at least some of the more significant distortions that are created by the existing arrangements, without necessitating fundamental change, for example:

- levelling the playing field between transmission-connected generation and embedded generation by:
  - modifying the DGRs so as to remove the requirement upon distributors to compensate embedded generators for avoided transmission costs;[128] and
  - allocating 'shared' connection costs to transmission-connected and embedded generators alike based on their AMI injections at the GXP;
- revisiting the rules relating to generators (and distributors) constructing, and assuming ownership of transmission links, including:
  - preventing generators from owning connection assets (or entering into analogous contractual arrangements with distribution companies), ie, requiring that all connection assets ultimately be owned by Transpower;
  - putting in place formal arrangements in the TPM to require 'first-movers' to be compensated by 'second- and third-movers' that connect subsequently to assets that have been funded by the first mover for a period;
- by reforming the application of the GIT to connection assets in two ways:
  - through Transpower requiring parties to connect at the most sensible location from an overall system perspective, where more than one location is technically possible, ie, by exercising the discretion provided by the Benchmark Agreement; and
  - allowing, in certain circumstances, for a new connection investment to be considered part of the interconnected network if the economic limb of the GIT is met, and socialising the attendant costs across multiple grid users.

However, there is not a consensus among the Working Group regarding the materiality of the issues that the suite of changes listed above would be intended to address. For these reasons, although the Working Group considers that it will need to be mindful of these issues in developing any option in the subsequent project phase, they do not warrant further exploration in the near term.

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[128] The alternative would be to put in place other mechanisms such as network support payments to allow transmission-connected generators (and potentially other non-network alternatives) to receive equivalent payments.

5.4. Introduce FTRs?

If FTRs were introduced to the New Zealand market it is likely that the FTR mechanism adopted would have strong similarities to the mechanisms in other leading LMP markets, notably the Northeast and Midwest United States. The FTRs would be likely to be available to energy market participants transacting across the transmission system, to hedge uncertain congestion costs inherent in LMPs. The MW quantity and point-to-point definitions of FTRs would most likely be defined by a central authority according to a load-flow analysis and, in the case of transmission expansions, would be auctioned to market participants. The auction funds raised would offset transmission expansion costs.

The issuance of FTRs cannot ever provide a ***substitute*** for the existing regulated transmission pricing and investment arrangements. Because of the practical complexities described in section 2.2, including free-rider problems, there will always be a need to recover at least a proportion of transmission costs through a regulated transmission pricing framework, where at least some of those prices are levied upon multiple users (or 'socialised'). Similarly, there will always be a need for some element of central transmission planning, eg, through the operation of an investment test such as the GIT.

The potential drawbacks with introducing FTRs include:

§ the assistance with transmission planning and cost recovery is likely to be quite limited;

§ there is a significant possibility that auctions of FTRs would raise only a modest proportion of the annual investment costs – especially given that investments are lumpy and so tend to eliminate congestion for a number of years at a time, ie, issuing FTRs may not reduce significantly the proportion of transmission costs that are socialised;

§ the potential for the exercise of *market power*, ie, in some or all locations there may be insufficient interested parties to constitute a competitive and therefore an efficient market for the purchase of FTRs; and

§ the resulting substantial increase in administrative complexity, including additional settlement complexity, organising auctions, and determining the net amount of capacity increase to associate with a FTR.[129]

In other words, there are likely to be significant additional regulatory costs associated with the introduction of FTRs. However, that is not to say that FTR products would not potentially ***complement*** the existing regulated transmission pricing and investment arrangements by delivering a number of ***other*** advantages. Indeed, designing and allocating FTRs may have a number of ancillary benefits, including:[130]

§ FTR valuations may provide at least *some* assistance to transmission planning by showing a market-based measure of relative transmission worth;

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[129] See Appendix D for a more comprehensive discussion of the administrative complexities likely to arise from the introduction of FTRs.

[130] Indeed, we understand that Transpower has an FTR product in the initial development stages that it intends to consult upon in the near-term, with a view to delivering these types of benefits.

- by reducing (but not eliminating) the net cost of expansions that are not assigned to specific users or beneficiaries, FTRs would reduce the proportion of total transmission costs that need to be shared across network users (although, as noted above, this reduction may only be modest) and to the extent they do, would better align payments for transmission with its beneficiaries of new transmission (this is a key objective of efficient transmission pricing); and
- once issued, FTRs become a tool that helps market participants hedge their volatile congestion costs,[131] and thereby reduce the uncertainty of transmission usage prices – FTRs might therefore broaden retail competition by allowing for the hedging of a wider geographic spread of retail customers.

These potential benefits *may* make the development of FTR hedging products worth exploring. Ultimately it is a question of degree. Specifically, if the benefits – which are likely to stem primarily from FTRs' utility as a hedging instrument (given that the contribution to investment costs is likely to be modest) – are sufficient to justify the resulting administrative complexity, then there is a case for their introduction. However, our preliminary view is that there is a strong possibility that the additional regulatory costs may outweigh the potential advantages, at least in terms of transmission pricing (as distinct from hedging benefits), in which case FTRs should not be introduced.

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[131] This has been raised as an issue in New Zealand and is said to have been a significant factor in power companies vertically integrating on a geographic basis in the absence of FTRs, so as to mitigate this risk (by creating a 'natural hedge').

6. Summary of Options

Many features of the existing transmission pricing arrangements are fundamentally sound, and are consistent with the objectives set out in section 1.1. For example, the arrangements ensure that system costs are recovered, and the nodal pricing and dynamic loss factor arrangements serve to minimise distortions to short-run operational signalling. The deep connection charging arrangements also provide additional locational signals by forcing connecting parties to trade off the additional costs of locating at various points with the additional costs of connection. The interconnection charging arrangements also provide appropriate incentives for off-take customers to reduce consumption at peak times in those regions that will soon require significant transmission investment.

However, the existing arrangements also exhibit a number of potential problems, namely:

§ the combination of nodal prices, losses, deep connection charges and the GIT may not be sufficient to signal the LRMC of transmission investment;

§ the HVDC charge is incapable of providing ***intra-island*** locational signals;

§ the circumstances and manner in which the GIT is undertaken are potentially problematic – most notably, because each transmission investment is considered in isolation, critical interdependencies with other projects may be overlooked and so the wrong investment option selected;

§ the 'deep connection' charging regime has the potential to distort the long-run investment costs signals associated with different generation alternatives, specifically:

  – because connection charges can vary substantially depending upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment signals can be created in some circumstances;

  – the arrangements for recovering the costs of 'shared' connection assets may give rise to significant step-changes in connection charges as 'beneficiaries' change over time, which can reduce certainty and further harm dynamic efficiency; and

  – the arrangements may give rise to 'first mover' problems, whereby individual generation proponents are unwilling to pay the deep connection charges to connect new generation locations;

§ levying HVDC charges on the basis of South Island generators' historic peak injections (HAMI) is said by some South Island generators to distort their use of and investment in peaking capacity, specifically:

  – the HAMI charging parameter does ***theoretically*** provide incentives to withhold supply of peaking capacity, although the circumstances in which it will be profitable to do so seem likely to be infrequent;

  – the incidence of the HVDC charge may reduce incentives to invest in the South Island (particularly in peaking capacity), although this may well be symptomatic of efficient locational signalling; and

  – the HVDC charge also increases the likelihood that new investment will be undertaken by established incumbent South Island generators (notably Meridian).

In other words, the existing arrangements have their share of strengths, and some weaknesses. In the following section we summarise the high-level options for reform to the current transmission pricing arrangements for consideration by the Steering Group.

6.1. Further Locational Signals

The nodal pricing arrangements, when combined with the application of the GIT and deep connection charging, may not be capable of playing a sufficiently prominent role to prevent sub-optimal locational decisions by generators. Moreover, the HVDC charge is incapable of providing ***intra-island*** locational signals. In other words, there may be scope for the TPM to be modified in some manner so as to provide superior locational signals – particularly to generators. The high-level options for introducing further locational signals are summarised in Table 5.

Table 5
Summary of High-Level Options for Introducing Locational Signals

Characterisation of Grid	TPM Option	Key Issues
Structural south-north flow that will drive new investment in that 'highway'	§ TPS methodology applied to generators § Residual charge on load based on RCPD § Shallow connection § No HVDC charge	Is the assumed structural characterisation valid?
'Bespoke' locational preferences, ie, focus on locations where load patterns are clear or on shorter-term investment requirements	§ 'Modified' TPS methodology applied to generators § Residual charge on load based on RCPD § Shallow connection § No HVDC charge	Would the estimated locational signals be sufficiently enduring?
Enduring characterisation not possible	§ Retain deep connection § No HVDC charge § Locational signals provided by nodal prices, deep connection and the GIT	Is there a feasible alternative to this 'default' position?

It follows that the critical decision facing the Steering Group is whether it is feasible to come to a settled view on an enduring characterisation of the transmission grid for a 10 to 20 year period, or a set of bespoke locational preferences over a similar period. In our view, Transpower is likely to be in the best position to establish an enduring characterisation of the grid, eg, based on its 10-year plus transmission development plan and the EC's SOO scenarios. Assuming that an enduring characterisation of the grid can be made, the combination of Transpower's indicative investment programme and the SOO scenarios should provide the basis for determining the appropriate extent of the 'tilt', and any reset.

Table 7 illustrates that, if no enduring characterisation is possible – even in specific locations – then the process of estimating long-run costs and developing robust price signals is likely to become unworkable. In these circumstances, the costs associated with grid upgrades would then need to be recovered by means of a 'tax' that would be designed so as to be as efficient as possible.

The design and application of the GIT is particularly important under such an option. In consequence, it is likely to become more important to address the potential shortcomings in the way in which the test is presently applied. In particular, if multiple transmission investments are intended principally to address the same problem, say, constraints in a particular importing region, then it would be beneficial for the interdependencies between these projects to be recognised in some way when undertaking the GIT. However, such an exercise is beyond the scope of this study, and has not been explored further in this report.

6.2. HVDC Charges

The justification for retaining the HVDC charge does not appear to be strong. Specifically, there appears to be good reasons to replace the charge with a TPS methodology capable of delivering a superior locational signal. Alternatively, if a TPS methodology cannot feasibly be implemented, then the same obstacles are likely to preclude one having any confidence in the locational signal being provided by the current HVDC charge. These considerations suggest that it should be removed, ie:

§ if a TPS methodology is implemented, the HVDC charge could be incorporated entirely into the interconnection charge and recovered from generators and load in the manner described in section 5.1.1 or 5.1.2; and

§ if a TPS methodology is *not* implemented, the HVDC charge could be either:

  – incorporated entirely into the interconnection charge; or

  – the costs associated with the Pole 1 replacement could be incorporated into the interconnection charge, with the remainder being recovered from South Island generators as a 'legacy charge'.

If some form of HVDC charge remains nonetheless (either the charge as presently formulated, or a 'legacy' charge), the most sensible alternative to a HAMI-based charge is a parameter based on a measure of capacity that is not dependent on usage, eg, nameplate capacity. However, we are not convinced that there are any fundamental problems with the HAMI-based charging parameter that might necessitate such a change.

6.3. Connection Charges

We cannot be confident that a *substantial* departure from the existing deep connection charging arrangements to implement, say, shallower connection charges or a 'but for' test, would deliver a material improvement upon the status quo. There are likely to be some advantages, but the potential disadvantages may be even greater. We note that the case for any shift to shallow connection charges is likely to be stronger if further locational pricing signals were to be implemented through the interconnection charge, as implied by the high-level options summarised in Table 5.

It is possible that more modest reforms may be capable of addressing at least some of the more significant distortions created by the existing arrangements, without necessitating fundamental change, for example:

- levelling the playing field between transmission-connected generation and embedded generation by:
  - modifying the DGRs so as to remove the requirement upon distributors to compensate embedded generators for avoided transmission costs;[132] and
  - allocating 'shared' connection costs to transmission-connected and embedded generators alike based on their AMI injections at the GXP;
- revisiting the rules relating to generators (and distributors) constructing, and assuming ownership of transmission links, including:
  - preventing generators from owning connection assets (or entering into analogous contractual arrangements with distribution companies), ie, requiring that all connection assets ultimately be owned by Transpower;
  - putting in place formal arrangements in the TPM to require 'first-movers' to be compensated by 'second- and third-movers' that connect subsequently to assets that have been funded by the first mover for a period;
- by reforming the application of the GIT to connection assets in two ways:
  - through Transpower requiring parties to connect at the most sensible location from an overall system perspective, where more than one location is technically possible, ie, by exercising the discretion provided by the Benchmark Agreement; and
  - allowing, in certain circumstances, for a new connection investment to be considered part of the interconnected network if the economic limb of the GIT is met, and socialising the attendant costs across multiple grid users.

However, there was not a consensus among the Working Group regarding the materiality of the issues that the suite of changes listed above would be intended to address. For these reasons, although the Working Group considers that it will need to be mindful of these issues in developing any option in the subsequent project phase, it does not consider that they warrant further exploration in the near term.

6.4. Introduction of FTRs

Designing and issuing FTRs would entail substantial additional regulatory costs, and would not obviate the need for the existing regulated transmission pricing and investment arrangements. However, it would also offer some potential benefits, including reducing (albeit perhaps not by very much) the proportion of transmission costs that must be socialised, and allowing market participants to hedge their volatile congestion costs. Ultimately it is a matter of degree. Our preliminary view is that there is a strong possibility that the additional regulatory costs may outweigh the potential advantages, at least in terms of transmission pricing (as distinct from hedging benefits), in which case FTRs should not be introduced.

[132] The alternative would be to put in place other mechanisms such as network support payments to allow transmission-connected generators (and potentially other non-network alternatives) to receive equivalent payments.

Appendix A. Indicative Investment Programme

This appendix summarises Transpower's transmission investment programme in coming years. The approach adopted by Transpower was to provide a preliminary assessment of the upgrades required for the New Zealand grid 'main trunk' that are caused by generators locating remote from major load centres. *Indicative* grid enhancements (ie, not necessarily committed and not necessarily 100 per cent accurate) out to 2035 have been identified for a scenario where generation is located remote from major loads, with the following provisos:

§ the objective is to provide a rough order of magnitude to test the TPS methodology concept – no additional transfer capacities have been provided;

§ only investments dealing with main trunk have been included – upgrades to customer connection/grid interconnection to meet demand have been ignored, ie, the list included only those investments driven by generation location decisions;

§ the underlying premise is need for strong south to north capability with generation more likely to locate south in absence of any other drivers; and

§ the investments assume 'normal' load growth, etc, – they do not anticipate new technologies that reduce peak capacity, etc.

North Island

Albany to Otahuhu
NAaN stage 1 – $500 million in 2014 – 500MW
UNI Reactive Support – $50 million in 2015 – 100MW
NAaN stage 2 – est $500 million in 2026 (additional cable) – 600MW

Otahuhu to Whakamaru
NIGUP stage 1 – $700 million in 2012 – 1000MW
NIGUP stage 2 – $500 million in 2030 (400 kV conversation) – 1700MW

Whakamaru to Wairakei
Wairakei Ring – $150 million in 2013 – 500MW

Whakamaru to Bunnythorpe
Lower NI Renewables stage 1 – est $500 million in 2017 (Major 220 kV reinforcement) – 600MW

Bunnythorpe-Stratford-Huntly
Reinforcement of 220 kV – est $100million in 2020 – 100MW

Bunnythorpe to Haywards
Lower NI renewables stage 2 est $150 million in 2020 (Major 220 kV reinforcement) – 600MW

HVDC
$700 million in 2012 – 700MW

South Island

Twizel to Stoke
Upper SI IGE – $100 million in 2007 – 150MW
SIGU II – $100 Million est in 2015 (SVC, diversity) – 150MW
SIGU II – million est $500 million in 2025 (New line) – 600MW

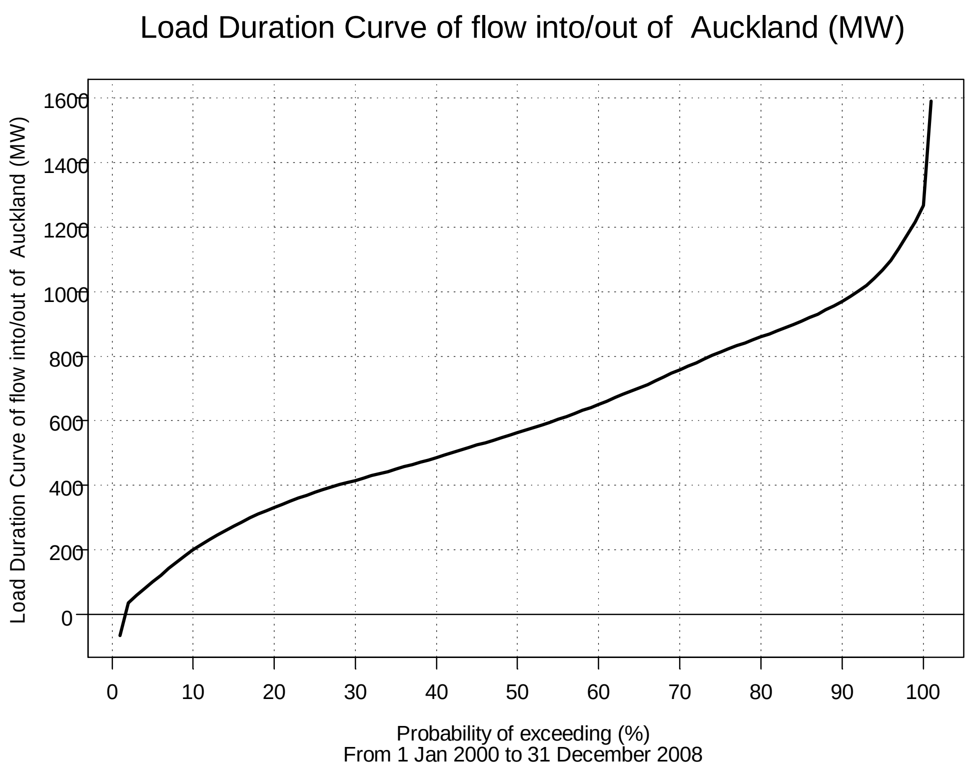
Twizel to Roxburgh
LSI renewables – $150 million in 2012 – 150MW
LSI renewables stage 2 – $ 300 million est in 2025 (new line) – 300MW

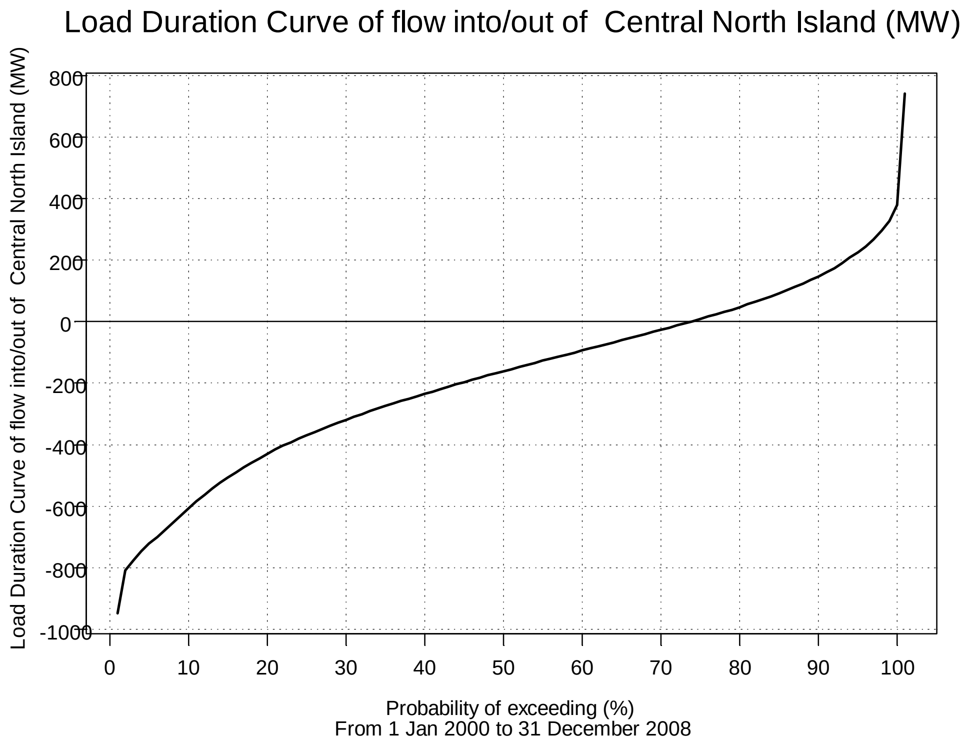
Roxburgh to Tiwai
LSI reliability – $150 million in 2015 – 150MW

Appendix B. Summary of Power Flows

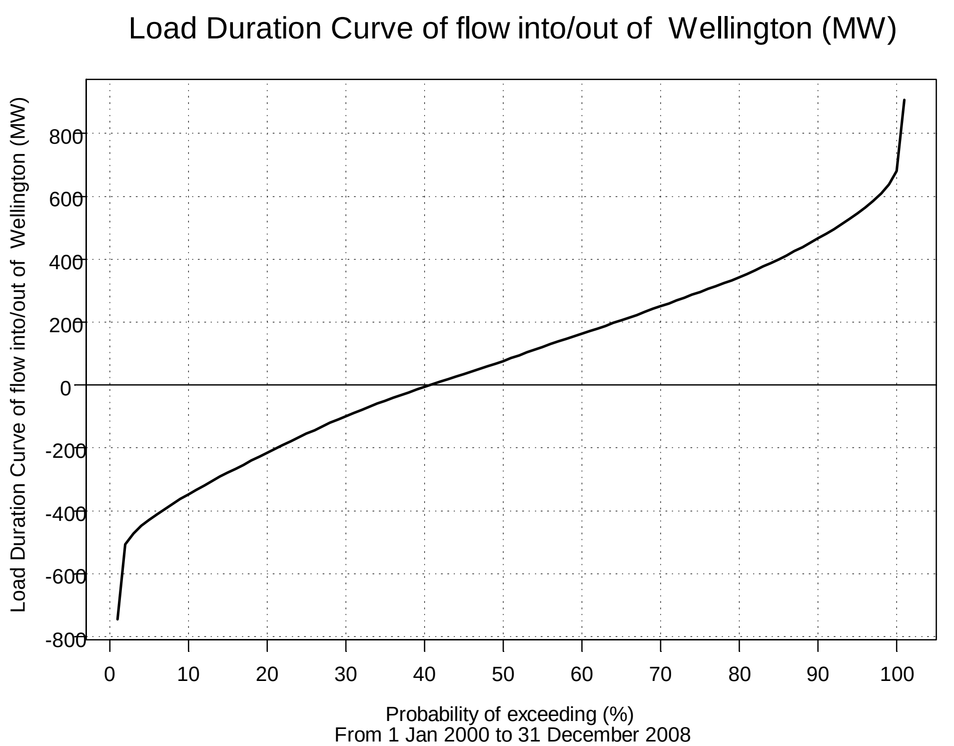
The following charts were supplied to the Working Group by Meridian. They have been derived on the following basis:

- Transpower branch flows from EM6 website, published from SPD engine, have been employed;
- branch flow is the calculated power flow through each component in the SPD model covering the major transmission lines;
- the flow into regions has been calculated by summing the part flows from each line entering that region; and
- power flows are analysed half hourly over the period from 1 January 2000 to 31 December 2008



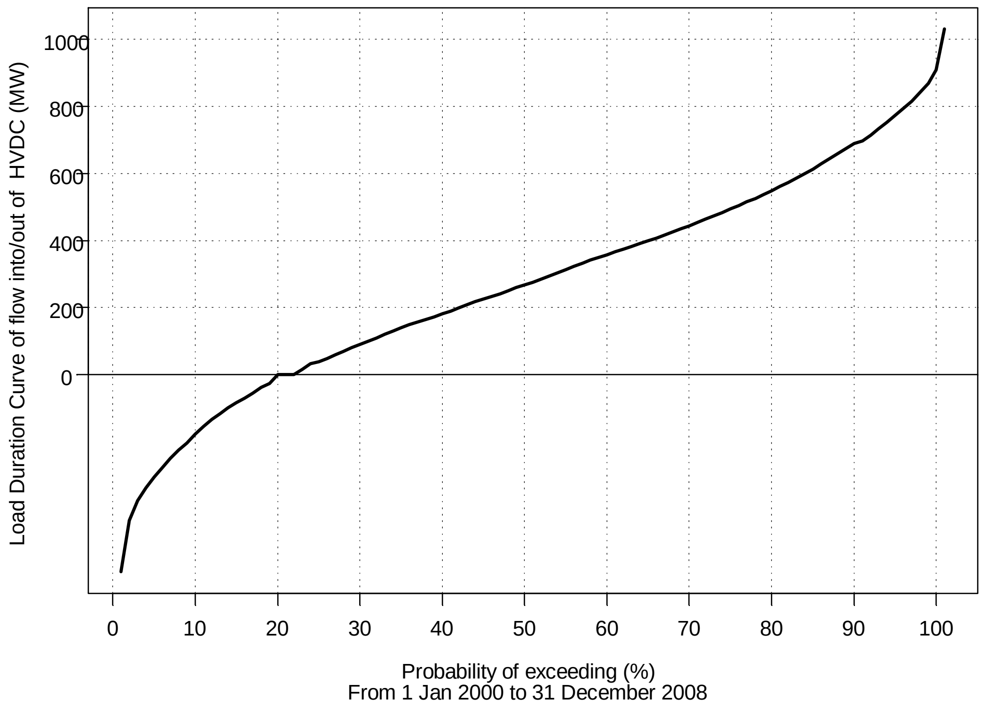


Load Duration Curve of flow into/out of Central North Island (MW)
Load Duration Curve of flow into/out of Central North Island (MW)
800
600
400
200
0
-200
-400
-600
-800
-1000
0
10
20
30
40
50
60
70
80
90
100
Probability of exceeding (%)
From 1 Jan 2000 to 31 December 2008

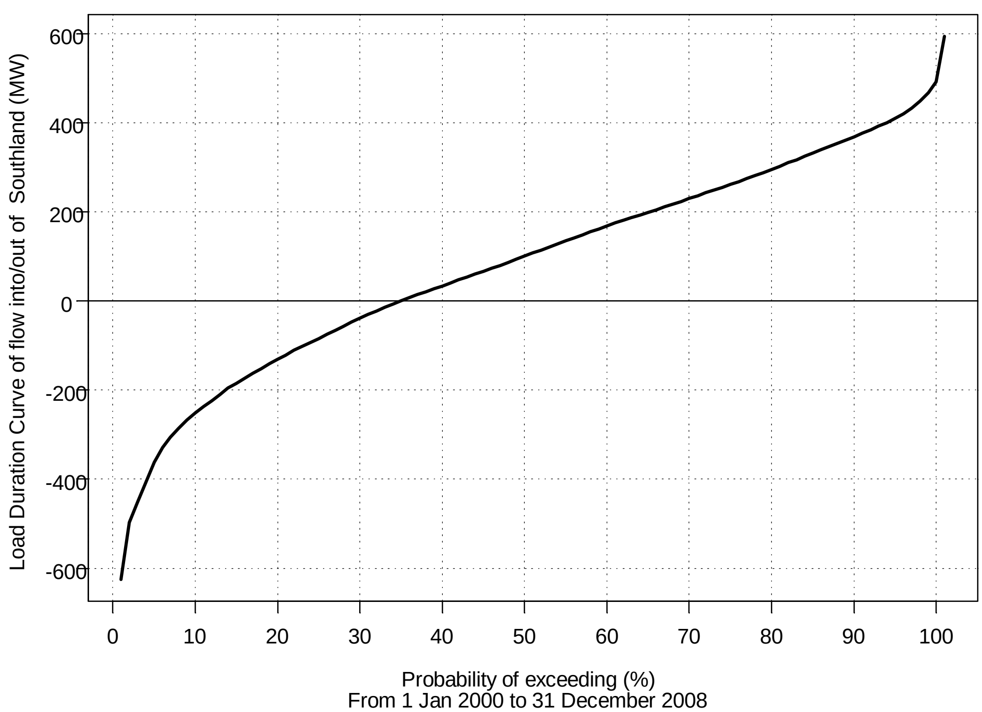


Load Duration Curve of flow into/out of Wellington (MW)
Load Duration Curve of flow into/out of Wellington (MW)
800
600
400
200
0
-200
-400
-600
-800
0
10
20
30
40
50
60
70
80
90
100
Probability of exceeding (%)
From 1 Jan 2000 to 31 December 2008

Load Duration Curve of flow into/out of HVDC (MW)



Load Duration Curve of flow into/out of Southland (MW)



Appendix C. Transmission Pricing Principles

2. Pricing principles

The principles to be applied by **Transpower** in developing the **transmission pricing methodology** and the **Board** in approving the **transmission pricing methodology** are as follows:

2.1 the costs of connection and use of system should as far as possible be allocated on a user pays basis;

2.2 the pricing of new and replacement investments in the **grid** should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options;

2.3 pricing for new generation and load should provide clear locational signals;

2.4 sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions made by **grid** users;

2.5 the overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints; and

2.6 transmission pricing for investment in the **grid** should recognise the linkages with other elements of market pricing (including the design of the **financial transmission rights** regime under section V, and any revenues from **financial transmission rights**).

3. Application and interpretation of pricing principles

3.1 In applying the pricing principles, **Transpower** and the **Board** should take into account practical considerations, transaction costs and the desirability of consistency and certainty.

3.2 Where conflicts arise in applying the pricing principles set out in rule 2, they should be resolved with the objective of best satisfying the **Board's** principal objective.

Appendix D. Market-based Transmission Investment

Traditionally, New Zealand electricity network businesses were seen as monopolies, and central planning processes were relied upon to manage and expand those networks efficiently. However, a reform process that began in the 1980s led eventually to the disaggregation of the industry into its components – generation, network and retail – and the introduction of competition in electricity generation and retailing. The spot wholesale electricity market, also known as the New Zealand Electricity Market (NZEM), began full operation on 1 October 1996, with spot prices based on *locational marginal prices* (LMP).[133]

The initial thinking in New Zealand (and elsewhere) was that the existence of LMP would give rise to the possibility of ***market-driven investment*** in transmission network infrastructure. Transpower did not (and still does not) have a statutory monopoly of transmission service in New Zealand, which left open the possibility of independent operators investing independently in transmission infrastructure. To this end, in 2002 the industry and the Government canvassed extensively the possibility of introducing financial transmission rights (FTRs) in order to create property rights that would improve the potential for market-led transmission investment.[134]

However, FTRs ultimately were ***not*** introduced and, to date, user-driven transmission investment has been limited to assets falling outside of the interconnected network, and there have been no transmission investments undertaken by independent operators. To understand why, one must appreciate the formidable *practical* challenges arising from other economic characteristics of transmission that were perhaps not fully appreciated when user-driven transmission investment was initially contemplated. This appendix discusses the challenges likely to arise in developing a framework for 'market-based' transmission investment, and sets out a framework for addressing them.[135]

D.1. Prices, Costs and Efficient Investment

Electricity transmission networks move electrical energy from one location to another. In the short-run, physical investment in the network is fixed. Indeed, the majority of Transpower's regulated revenue – and hence most of what needs to be recovered through its prices – comprises a return on existing, sunk network assets. In consequence, the short-run costs of transmission consist of:

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[133] Specifically, spot prices in NZEM are calculated using the price offers and demand bids made by generators and market customers. Offers are accepted in order of price until enough generation is dispatched to meet demand, taking into account reserves requirements, transmission constraints and losses. The spot price at each of the 244 'grid nodes' in the system is set equal to the marginal cost, calculated based on offer prices, of supplying an additional increment of demand at each node. All dispatched generators are then paid a price based on the market clearing price at their location, independent of their original offer price. Prior to full nodal pricing being introduced in 1996, New Zealand operated a "shadow" LMP market from 1992 to simulate the effect of LMP prior to restructuring.

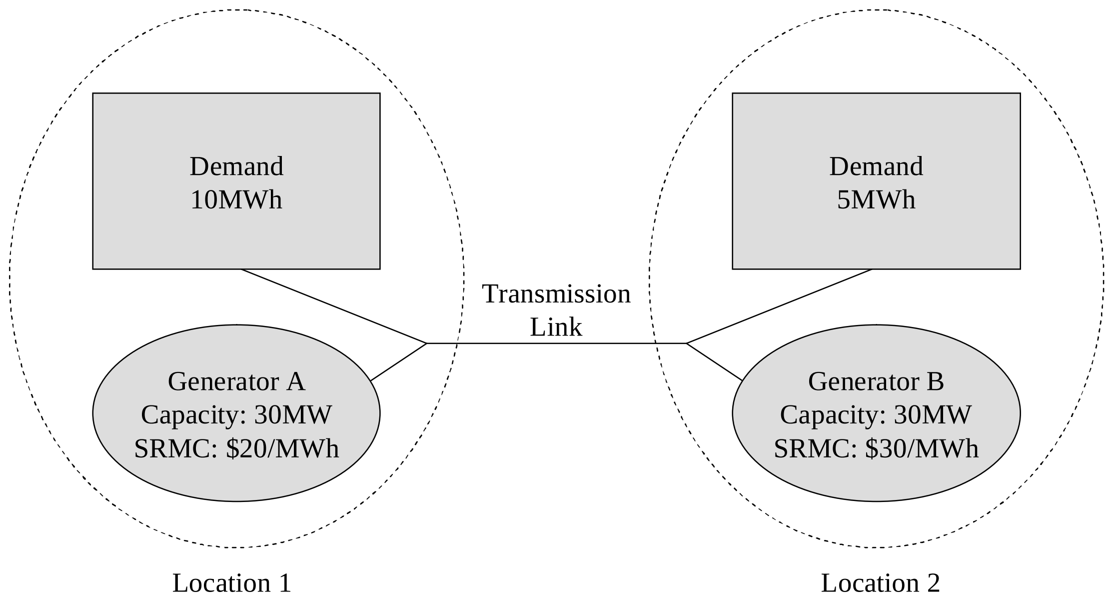
[134] Such rights were intended also to allow market participants to hedge locational price risk resulting from transmission congestion. See: E Grant Read, *Financial Transmission Rights for New Zealand: Issues and Alternatives*, prepared for the New Zealand Ministry of Economic Development, 8 May 2002.

[135] Many different terms are used for transmission investment undertaken by the private sector, including unregulated interconnectors, and entrepreneurial interconnectors. Since these terms often have particular meanings to individual people, we use the term 'market-based' investment in this paper as a more generic term.

- the physical energy losses incurred; and
- the 'opportunity cost' of any constraints or congestion on the network.

When a transmission network is congested, the short-run alternative is to deploy more expensive generation from a different location. The short-run marginal cost of transmission is therefore determined by the cost difference between the cheaper generation and that which must be used because of the network constraint. Under an LMP framework, the short-run marginal cost of transmission between two nodes is represented by the ***difference in the spot*** *prices at the two nodes*. **Error! Reference source not found.** illustrates the short run costs of transmission, and their link to optimal dispatch and spot market prices.

Figure D.1
Spot Prices and the Short-run Cost of Transmission



If transmission is costless, optimal dispatch will involve accepting the lowest cost generator (or demand-side bids) until demand is satisfied. In this case, generator A will be dispatched first and, in the above example, it will be able to satisfy demand in both locations 1 and 2. Generator B will not be dispatched. Assuming that generators bid at their short run marginal cost (SRMC), the spot price in each location will be $20/MWh.

But transmission is *not* costless. First, there is the cost of energy losses as power flows along the wires. If the cost of energy losses is less than $10/MWh, costs will still be minimised by dispatching generator A to both locations. If the marginal energy loss is, say, $5/MWh, then the marginal cost of energy in location 1 (assuming there are no losses within that location) is $20/MWh, equal to the generation cost. The marginal cost of energy in location 2, however, has risen to $25/MWh. If spot prices reflect the cost of losses, then the spot prices in the two locations will diverge. The marginal cost of transmission is equal to the difference in spot price between the two locations – in this example, the marginal cost is $5/MWh.

Now imagine there is a transmission constraint between the two locations. Generator A can no longer serve the full demand in location 2 because of the transmission constraint.

Therefore generator B must be called upon to generate. The marginal cost of generation is now \$20/MWh in location 1, and \$30/MWh in location 2. The constraint is an additional transmission cost – it is an 'opportunity cost' of not being able to use the cheapest generation source. Again, the short run cost of transmission will be reflected in the difference between the spot prices in the two locations, which now reflects the cost of losses, plus the cost of constraints.

In other words, the short-run costs of transmission are those that vary with respect to the flows of energy over *existing facilities*, ie, with respect to the scheduling and dispatch of generation and load. However, in the long run, *all costs* are variable. The existing network needs to be maintained, and capacity can be expanded. The long-run costs of transmission are therefore those associated with maintaining and/or expanding the network.

There is a strong link between the short-run costs of transmission, the long-run costs, and efficient investment in both transmission and generation assets. In the first instance, increased transmission demand can be met by increased energy losses across the network. As congestion occurs, alternative (more expensive) generation must be sought. In the long-run, the cost of losses and constraints rises until the point where it is cheaper to augment the network. In the example above, customers in location 2 are paying \$10/MWh extra because of losses and congestion on the transmission link. If additional capacity can be built and run for less than \$10/MWh (including losses), then it will be worth undertaking this investment.

Bearing these factors in mind, from an economic perspective, the conditions for optimal expansion of the transmission network are as follows:

- additional capacity should be built only if the total savings in the cost of generation (and demand management) exceed the total construction and operating costs; and
- additional capacity should be sized such that the marginal cost of generation savings and loss reductions (indicated by the difference in future spot prices – or generation costs – at different locations) equals the marginal cost of building and operating the additional capacity.

The optimality conditions are the core rationale for market-based investment in transmission. In principle, if network users are paying the costs of losses and constraints when they buy energy, then they will have an incentive to augment the network (at their own cost) if this is cheaper than the continuing cost (to them) of losses and constraints. In fact, users will have an incentive to invest up to the point where the cost of investing in one more unit of capacity (the long run marginal cost) is equal to the avoided cost of future constraints and losses (the short run marginal cost), as signalled through spot prices.[136]

In principle, such investors need not receive a regulated revenue stream. Rather, the motivation for investment is to avoid the costs of future losses and congestion (either in the present or in future). However, as we explain further below, to ensure that investors do not lose the benefits of their investment, they must receive a right to any network 'congestion

[136] In the previous example, we said that it would be worth expanding the network if additional capacity cost less than \$10/MWh. If the long run marginal cost of capacity was exactly \$10/MWh, then the long-run cost of expansion is equal to the remaining short-run cost of losses and constraints.

rents', ie, revenue that arises from a divergence in the spot price between locations, should the link in which they have invested become congested in the future. Such rights might be 'physical rights' to the dedicated infrastructure, or FTRs that are of a purely financial nature. Such rights ensure that, if congestion does arise on a transmission link, those who invested in the link are financially compensated and so can be sure of avoiding the costs of congestion that underpinned the rationale for their investment. Under this paradigm, users will base their decision to invest in network expansion on their expectations of future spot prices.

It follows that, ***in principle***, efficient investment signals can be provided by market prices, rather than by central planning. In addition to their fundamental role in providing a means for those who may contribute to financing the provision of transmission capacity between to nodes to protect themselves from the risk of that link subsequently becoming congested, the issuance of FTRs can also deliver a number of other potential benefits, including:

- by reducing (but probably not eliminating) the net cost of expansions that cannot be assigned to specific users or beneficiaries, new investment will reduce the proportion of total transmission costs that need to be shared across network users; and
- once issued, FTRs become a tool that helps market participants hedge their volatile congestion costs137 – FTRs might therefore broaden retail competition by allowing for the hedging of a wider geographic spread of retail customers.

There is significant international precedent for FTRs, including in the Pennsylvania, New Jersey, Maryland (PJM) and New York electricity markets. To this end, in 2002 the industry and the Government canvassed extensively the possibility of introducing FTRs in order to create property rights that would improve the potential for market-led transmission investment.[138] However, as noted above, FTRs ultimately were ***not*** introduced and, to date, market-driven investment has not occurred. There are a number of reasons why market signals, by themselves, have not brought about such investments, and are unlikely ***ever*** to lead to an optimal level of investment. One consequence is that for an FTR-based framework to deliver efficient transmission investment there will always be a need for a robust regulatory framework that involves some centralised decision-making in determining transmission investment and prices. The analysis and reasoning behind this conclusion is explained in the following section.

D.2. A Framework for Market-based Investment

There is no single 'model' of market-based transmission investment. The detailed framework needs to be developed in the context of the specific features of the market where it is being proposed. Nonetheless, there are a number of principles that any such framework must take into account if its objectives are to be met. This section sets out the main elements that are

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[137] This has been raised as an issue in New Zealand and is said to have been a significant factor in power companies vertically integrating (to create 'gentailers') on a geographic basis in the absence of FTRs, so as to mitigate this risk (by creating a 'natural hedge').

[138] Such rights were intended also to allow market participants to hedge locational price risk resulting from transmission congestion. See: E Grant Read, *Financial Transmission Rights for New Zealand: Issues and Alternatives*, prepared for the New Zealand Ministry of Economic Development, 8 May 2002.

necessary for a system of efficient market-based transmission investment. These elements are:

- a competitive wholesale spot market that incorporates locational prices, ie, price differentials when the network is congested and price differentials to account for transmission losses;
- FTRs allocated across the capacity that exists between all such locational prices, and to all new investment to ensure that those who invest in network expansion retain the benefits of that investment;
- open access to the transmission network;
- a regulatory framework that supports market-based investment, for example in:
  - defining and allocating FTRs;
  - ensuring that externalities are accounted for, including network effects; and
  - ensuring that efficient investment is undertaken in situations where there are economies of scale; and
- 'regulated' investment in some circumstances, for example:
  - within those (meshed) parts of the network where prices do not signal investment requirements and/or where beneficiaries may be difficult to define; and
  - in cases where coalitions of users are difficult to form because the benefits of investment are widespread.

The New Zealand Electricity Market (NZEM) already has some of these building blocks. It incorporates nodal spot prices that vary with losses and congestion and it has a policy of open access to the (interconnected) network. The principal steps necessary to move towards market-based investment in the NZEM include:

- introducing a system of FTRs that is integrated with investment in the network; and
- developing a framework for regulated or centrally-planned transmission investments that supports, but does not 'crowd out' market-based investment.

The following sections examine each of these steps. They illustrate that regulation plays an important role in ensuring efficient transmission expansion, whether it occurs through central planning or through market-based investment.

D.2.1.Financial Transmission Rights

When users pay for a new transmission link, the benefit they receive is that they are relieved from paying congestion costs and additional losses. However, once the transmission line is in place, other users will also be able to use the link (assuming open access). New generators or customers may connect, and demand may grow. As a result, the line may become increasingly congested, with losses increasing and constraints appearing at peak times.

To give users an incentive to invest in transmission links, they must be able to capture the benefits of reduced congestion and losses. Such benefits must be defined and allocated through FTRs. These rights do not give the holder any *physical* access rights to the network.[139] Instead, they give the holder the financial benefit of the link *as if it were uncongested*, whether or not it is congested in practice. It does this by giving the holder of the FTR a *right to the difference in the pool price* between the two nodes (for a certain capacity).

The right to the difference in pool price is provided by giving the FTR holder a right to the 'settlements surplus'. Where the total FTRs issued equals the capacity of the link, then the settlements residue will exactly offset the payments to holders of FTRs. To ensure efficiency, these rights need to be fully tradable on a secondary market. This will ensure that at any time the people holding the transmission rights will be those who place the highest value on them.

There are two separable parts to devising a system of FTRs – allocating rights to use of the *existing network*, and putting in place a system of rights for any *future network expansion*. Rights cannot feasibly be issued to use the capacity arising from network expansions without also being issued to use the existing network capacity. Rights to new capacity need to take into consideration the *capacity* of the new investment,[140] and any *externalities* resulting from the new investment. These issues are discussed in sections D.2.2.1 and D.2.2.2.

An important challenge that may arise in the sale/auction of FTRs, particularly given the characteristics of the New Zealand market, is the potential for the exercise of *market power*. Specifically, in some locations there may be insufficient interested parties to constitute an efficient market. This possibility would also need to be given careful consideration in the design of any FTR regime.

D.2.2. The Role of the Regulator

Building new transmission links simply cannot proceed in a fully decentralised or market-based manner – there is a need for both technical and economic regulation. On the technical side, regulation is necessary to ensure that the new link will not endanger the safe operation of the integrated network. On the economic side, regulation plays a role in:

- defining and allocating the financial rights to the link;
- ensuring that 'externalities' are properly accounted for, eg, network effects that may either enhance or compromise the capacity of elements of the existing network, and so affect the existing portfolio of FTRs;
- ensuring that efficient investment occurs when there are economies of scale;
- acting as a 'back-up' to the market where it does not deliver efficient investment, eg, within the meshed network, or where benefits are widespread; and
- retaining a right of veto over investments where they are not economic.

It follows that some form of regulatory role will remain pivotal in any network expansion. A critical question that must then be considered is the appropriate entity or entities for undertaking this regulatory role. In New Zealand, the most obvious candidates would be the

[139] Physical access rights are inconsistent with an open access regime, and with efficient dispatch.

[140] In some cases this may vary depending on flows in the rest of the network.

Electricity Commission or the Commerce Commission. In the following sections we examine that role in more detail by reference to the various tasks above.

D.2.2.1. Defining and Allocating Rights

The effective capacity of a link may vary, depending on the energy flows in other parts of the network. We noted above that, with full nodal pricing and with FTRs allocated for both the whole network (for a feasible set of operating conditions), the amount raised in settlements residue across the whole network will always be sufficient to cover the FTR obligations.

However, this may not be the case if rights have not been allocated across the whole network.[141] In this situation, if rights are allocated for the full capacity of the link, there may be times when the physical capacity is *less* than that allocated. At these times, the settlements residue collected will be less than the value of the FTRs that arise. Alternatively, if rights are only allocated on the basis of the capacity of the link at its reduced level, there will be times when the settlements residue is greater than the FTRs associated with the link.

There are a number of potential ways to address this problem, including:

- to offer rights that are differentiated by time of day, ie, if capacity varies with a clear pattern, depending on the time of day, then rights could be matched to this pattern – although, this is likely to reduce rather than eliminate the problem;
- to define financial rights in terms of a proportion of the settlements residue arising, rather than rights to a specific capacity on the link; however, this raises other difficulties, including:
  - those who purchase rights on the line no longer have any certainty about the financial compensation they will receive when there are transmission constraints; and
  - in consequence, their FTRs no longer act as perfect hedges – some risk of price divergence will remain, because they do not know the exact level of capacity for which they will be compensated;
- to define rights for the smaller capacity, which would result in a surplus of settlements residue that did not need to be returned to FTR holders – this surplus could then be returned to network users or investors (closer examination would need to be made of the effect on incentives to invest in efficient infrastructure, since the allocation of rights would effectively be understating the capacity that was in fact available); and
- to allocate FTRs to the maximum capacity, which would result in a shortfall between the settlements residue and the FTRs, that would need to be made up through a 'network charge' on users – in allocating the network charge, the objective should be to minimise any distortionary impact of the charge on the behaviour of network users.

The relevant regulator will inevitably have a central role in defining and allocating the financial rights to the link, and in resolving the difficulties described above associated with variable transmission capacity. This is likely to be a complex task involving a significant degree of market intervention.

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[141] Or if prices are regional rather than nodal, which is not the case in New Zealand.

D.2.2.2. Determination of Rights with Network Externalities

Network interactions are often complex. Building a new transmission link in one part of the network can have flow-on effects to other parts of the network. For example, it may result in an increase in effective capacity in some parts of the network, and a decrease in effective capacity in other parts of the network. Similarly, the effective capacity of a transmission link may depend on augmentation to another part of the network. In other words, a new transmission link in one area may affect the holders of FTRs in another area, in either a positive or negative sense. These effects are known as 'externalities'.

Individual investors will not take into account the effect of their investment (either positive or negative) on other parts of the network, and on other users. By not taking account of the total costs (benefits) of their investment, they have an incentive to over (under) invest. In consequence, to secure an efficient level of investment, the regulatory framework needs to ensure that investors take account of externalities when they are making investment decisions. There are a number of options for dealing with externalities, including:

- to allocate FTRs to the investor that reflect the *full network effects*, such that:
  - if the investment *increased* effective capacity elsewhere in the network, then the investor would receive FTRs for that additional capacity; and
  - if the investment *reduced* flows on other parts of the network, the investor would be required to buy back their lost FTRs from the relevant holders, thereby compensating users elsewhere in the network whose rights were being reduced; and
- to subsidise the investment where there are positive externalities (funded by a network charge), and to require compensation where there are negative externalities.

In practice it may not be straightforward to measure the externalities resulting from a network investment. Indeed, the complexity of the network can make it difficult to predict exactly how a new investment will affect capacity or electrical flow elsewhere. Furthermore, the effective capacity of any link may vary from one period to the next as demand and supply conditions across the network change. Allocating transmission rights in such circumstances is likely to be very challenging, requiring extensive regulatory intervention to adjudicate on the network effects of new investments, where those effects may be highly uncertain.

D.2.2.3. Economies of Scale

In section 0 we explained that, in principle, users will have an incentive to invest in transmission capacity up to the point where the cost of investing in one more unit of capacity (the long run marginal cost) is equal to the avoided cost of future constraints and losses (the short run marginal cost), as signalled through spot prices. If transmission investments exhibited *constant returns to scale*, then capacity could indeed be added incrementally until the long run marginal costs of adding a unit of transmission capacity exactly equalled the short run marginal cost of not adding capacity. However, they do not.

Rather, transmission investment exhibits significant *economies of scale or scope* – higher capacity links are always cheaper in unit cost terms. In consequence, efficient transmission investments are likely to be *lumpy*, and may therefore lead to significant changes in the market prices for energy. This has a number of consequences:

- changes to network capacity may appear to diverge from long run equilibrium for long periods of time, such that SRMC diverges substantially from long-run incremental cost (LRIC) for lengthy periods, for example:
  - when new capacity is installed, it may yield little benefit on the margin, eg, the near-term benefits may be provided by, say, the first 50 per cent of capacity added; and
  - at a much later stage, the second 50 per cent of added capacity will presumably yield substantial benefits.
- the 'standalone cost' of increasing network capacity is likely to exceed the cost of expansion by the network owner; and
- prices equal to SRMC will not be sufficient to recover total cost under a program of efficient capacity expansion (nor will prices equal to LRMC), which means that if their only incentive to invest is to avoid the short-run costs of transmission (losses and constraints), users will tend to under-invest.

In consequence, efficient investment requires a continuing role for 'central planning' or regulation. For example, in order to ensure that efficient investment occurs, a framework may be required to subsidise the additional investment cost through a network charge of some description. The regulator (or another independent body) will inevitably need to make an assessment of investment projects that exhibit economies of scale, to determine the network charges that can be passed through to network users.

D.2.2.4. Regulated Investment as a Back-up to the Market

The market-based investment framework requires network users who will benefit from a new investment to form a coalition to invest. In some cases, the beneficiaries of a link may be difficult to identify, or very widespread. For example, investment to ensure reliability may benefit many users, and a coalition may be difficult to form. Alternatively, it may be difficult to identify beneficiaries or to define rights in the meshed part of the transmission network. Exacerbating this problem, individual beneficiaries will have an incentive to 'free ride', hoping that the link will be built by others, so they can take advantage of it without contributing towards its cost.

In such cases, the regulatory framework needs a mechanism to ensure that efficient investment takes place. Again, this implies a significant and continuing role for some centrally-planned investment, and so the need for a strong regulatory function. The challenge in designing the rules for regulated investment is to ensure that it picks up those situations where the market does not provide efficient investment, but at the same time does not 'crowd out' market-based investments by skewing incentives towards regulated investments – assuming facilitating market-based investments remained a relevant objective.[142]

[142] One possible approach would be to require the central planner to put potential expansions out to tender, with the investors having the rights to FTRs. If there were no takers the central planner could resort to a regulated investment, funded by a regulated charge.

D.2.2.5. Right of Veto

In some circumstances, where FTRs have not been allocated to both the existing network and new assets, private sponsors may promote an investment that is not cost effective, simply in order to capture economic rent. In essence, there may be a transfer of benefits between different market participants, rather than any genuine economic gain. In these circumstances a regulator may need the power to veto the investment, since it does not give rise to a net economic benefit, eg, on the grounds that it does not meet the Grid Investment Test (GIT).

D.3. Implications for Transpower

This section discusses some of the implications of a market-based investment framework for Transpower, recognising that the precise effects will depend on the details of the framework put in place. Specifically, we discuss potential effects in relation to revenue regulation, service standards and risk allocation.

D.3.1.Revenue Regulation

Transpower has invested in the *existing* transmission network on the basis of the existing regulatory framework, which involves central network planning and incentive-based monopoly regulation. It is fundamental that modifications to the regulatory framework to facilitate market-based investment should not undermine the regulatory rights and obligations that have been established. If the 'goal posts' are constantly being shifted by the regulator, it will be less willing to invest in the future (and will require a higher return to allow for regulatory risk).

Introducing a system of FTRs for the existing network does not necessarily require a wholesale move away from the current regulatory arrangements administered by the Commerce Commission. Changes are more likely to be in terms of particular elements of regulation, such as service performance requirements (discussed below). These may well have implications for Transpower's risk profile, or the level of service it provides, and these would need to be reflected in the calculation of its allowed revenue.

The regulatory framework facing Transpower for new network investment will vary depending on the framework developed for market-driven investment. Transmission investment will be prompted by investors who foresee the cost of the investment being less than the future costs of losses and congestion in the current framework. Transpower could play an active investment role in new expansions, but this may be inconsistent with the risk profile its shareholders see as appropriate, and may give rise to potential conflicts of interest given the risks that it may need to bear in terms of service performance.

It is more likely that network users will see the benefit in investing in new network capacity to reduce the costs of congestion and losses. The role of Transpower would then be to provide information that allows such opportunities to be identified, and then to build, own and operate the transmission link. The operation of the link would be subject to the regulation of the network (in terms of technical standards, reliability, and the requirements of the central dispatch and spot pool arrangements, etc). The commercial arrangements of the link are likely to be governed by long term contracts between the investors and Transpower.

In those cases where the beneficiaries of the link are widespread, and a coalition of users cannot be easily formed, it is likely that a regulatory process will exist to ensure that efficient investments go ahead. In this situation it could be expected that Transpower will retain a role in network planning (possibly in conjunction with the Electricity Commission), and that the long-term commercial contract will be between the Transpower and the regulator, on behalf of customers. In this type of contract, the regulatory framework may be very similar to the regulation for existing networks, with some form of incentive-based regulation.

D.3.2.Service Standards

The allocation of rights to transmission services puts a spotlight on the ability of Transpower to provide the network services when they are needed. If the network is unavailable at a time of peak demand, the divergence in pool price between locations could jump substantially. If FTRs are defined in absolute capacity terms, the unavailability of some capacity on a link will result in a shortfall between the settlements residue collected, and the payments to holders of FTRs. This raises the question of the extent to which Transpower should bear the risk for the unavailability of its network or, alternatively, if Transpower is not to bear all the relevant risks, who should?

Providing Transpower with some incentives to make the network available at peak times makes good sense. The divergence in spot prices between two markets indicates a real cost of transmission capacity being unavailable. Transpower needs to be able to weigh up the potential cost of network failure with alternative decisions it might take, such as incurring higher maintenance costs. However, the form of the incentive would need careful thought. While it is responsible for ensuring that it maintains the existing network, network reliability also depends on other factors, such as weather conditions, and any regulatory criteria that govern when centrally-planned expansions take place. If Transpower does not have full control over expansions, it should not be held fully responsible for any breakdown in reliability.

D.3.3.Risk Allocation

The allocation of risks to Transpower in a market-based framework depends to some extent on the details of the framework put in place. We have suggested above that the risks faced by Transpower may be affected as follows:

- for the existing network, revenue regulation may remain largely unchanged. However, the allocation of FTRs will increase pressure on Transpower to make the network available at peak times. The risks allocated to Transpower depend on the definition of FTRs (eg, fixed or variable capacity), and the set of performance incentives put in place;
- for new market-based investment, Transpower may or may not take an active role in the investment decisions. If it takes an active role, it will face the risk that pool prices do not turn out as expected. If it does not take an active investment role, its risks will be determined by the contract provisions with investors. It is also likely to face service performance related risks, to ensure the network is available during periods of peak demand;
- Transpower may find it is exposed to greater competition in building, maintaining and operating transmission lines. The *Electricity Governance Rules* as they currently stand do

not give it any monopoly rights, and a move towards market-based investment would increase the likelihood of proposals from competing infrastructure providers; and

- Where Transpower undertakes investment that is a 'back-up' to the market-based investment, its risks will be determined by its 'regulatory contract' with the regulator – either the Electricity Commission or the Commerce Commission.

D.4. Conclusion

In principle, efficient investment signals can be provided by market prices, rather than by central planning. However, pure 'market-based' transmission investment is a misnomer. Regulation will continue to play an important role in ensuring efficient transmission expansion, whether it occurs through central planning or through market-based investment. On the technical side, regulation is necessary to ensure that the new link will not endanger the safe operation of the integrated network. On the economic side, regulation plays a role in:

- defining and allocating the financial rights to the link;
- ensuring that 'externalities' are properly accounted for, eg, network effects;
- ensuring that efficient investment occurs when there are economies of scale;
- acting as a 'back-up' to the market where it does not deliver efficient investment, eg, within the meshed network, or where benefits are widespread; and
- retaining a right of veto over investments where they are not economic.

Undertaking these tasks is likely to be very challenging, to require extensive regulatory intervention and to involve considerable additional regulatory costs. In other words, although market-based investment may partially supplant the current roles of Transpower (and, to an extent, the Electricity Commission) in the transmission investment function, it does not obviate – or necessarily even ***reduce*** – regulatory oversight. Rather, it introduces many additional challenges that are not easily resolved.

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