Decision-making and economic framework for transmission pricing methodology review

Consultation Paper

26 January 2012

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Executive summary

Introduction

1. The Electricity Authority (Authority) is responsible under section 16(1)(b) of the Electricity Industry Act 2010 for making and administering the Electricity Industry Participation Code 2010 (Code), which includes, as Schedule 12.4, the Transmission Pricing Methodology (TPM).

2. The purpose of this paper is to describe and consult on the decision-making and economic framework that the Authority will use to make decisions in relation to the TPM. Consideration of a clear framework for the Review of the TPM should contribute to robust decision-making. The Authority considers that instituting a comprehensive and durable decision-making framework is warranted, particularly given the ongoing debate about the TPM.

Decision-making framework

3. The TPM is a schedule to the Code and so any change to the TPM requires an amendment to the Code. The TPM must therefore be consistent with the Authority's statutory objective, which is "*to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers*."[1]

4. Consistent with the Authority's interpretation of the statutory objective, the framework for decision making about options for the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers. This recognises that competition is an important tool to encourage efficient outcomes and that measures that impact on reliability outcomes should encourage efficient trade-offs between the costs and benefits of reliability.

5. This overall efficiency refers to both efficient use of the grid and efficient investment in the electricity industry – the grid, generation and demand-side management:

   (a) efficient use of the grid focuses on least cost production and charging customers the efficient marginal costs of production; and

   (b) efficient investment focuses on the lowest cost development of the industry over time.

Market-based charges

6. The Authority's preliminary view is that its first preference is for market-based approaches to determining transmission charges, wherever it is confident such charges

[1] Electricity Industry Act 2010, section 15.

will be efficient and their implementation will be practicable and that any Code changes needed comply with the Authority's Code amendment principles, including those elements relating to cost-benefit analysis. Market-based charges would best achieve the Authority's statutory objective by promoting efficient outcomes in the electricity industry, including by providing a durable and stable TPM.

7. A market-based approach to charges would involve either charges established by the interaction of buyers and sellers in a workably competitive market or charges which are likely to mimic or replicate such charges. The Authority's preliminary view is that it would prefer charges that are established by the interaction of buyers and sellers rather than charges that seek to replicate the outcome of market interactions.

8. Although the development of a market-based approach to grid charges using nodal price differentials and transmission loss and constraint rentals has not proved a practicable means for funding all grid assets, a market-based approach based on long-term contracting has been adopted in New Zealand for charging for connection assets.

9. A market-based transmission charge was proposed by the Transport Working Group (TWG) of the Electricity Governance Establishment Committee (EGEC) in 2001-2 as part of a grid and transmission alternatives investment framework. This charge involved payments for all upgraded grid assets – connection, interconnection and HVDC assets – on a long-term contractual basis.

10. The other main market-based charge, which was considered by both the Electricity Commission and the Transmission Pricing Advisory Group (TPAG), is capacity rights, particularly for the HVDC link. TPAG noted: "*In relation to capacity rights, a range of views exists. Capacity rights would appear more costly to implement than other options, but its benefits may be significant, particularly if it reveals willingness to pay. However, if a capacity rights option were to be considered further, a range of substantial issues would need to be considered….*" The Authority is therefore seeking views on whether there would be any merit in it devoting further effort to developing a market-based TPM for interconnection and/or HVDC link assets.

Administrative approaches to charging

11. In situations where a market-based charge is inefficient an administrative approach to charging would be required. It is proposed that, if it is required to consider an administrative approach to setting transmission charges, the Authority's preliminary hierarchy of preference among administrated approaches will be:

    (a) exacerbators pay, where an 'exacerbator' is defined as a party whose action or inaction led to the cost in question;

    (b) beneficiaries pay, where a 'beneficiary' is defined as a party for whom the private benefits of the investment exceed the costs, and would therefore be willing to pay for it if that were the only means by which the benefit could be acquired; and, finally

(c) alternative charging options.

12. The more preferred approach would be applied wherever such charges will be efficient, implementation will be practicable, and any Code changes needed comply with the Authority's Code amendment principles. If a more preferred approach is unable to meet these requirements and raise all the revenue required the Authority will consider the next ranked approach.

13. Making exacerbators face the costs of their decisions would eliminate provision of the good or service when the cost exceeds the benefit to exacerbators, and so improve the performance of the economy as a whole by reducing wasteful activities. Charging beneficiaries, however, only ensures that those who would be willing to pay are required to do so. If the party's use of the grid asset is not voluntary, the user may not be a beneficiary.

Exacerbators pay

14. Under exacerbators pay the party or parties whose actions or inactions led to the cost in question is responsible for mitigating that cost. To ensure exacerbators have incentives to make efficient decisions, in theory the price they face should be based on the long run marginal cost (LRMC) for the grid of their actions or inactions. However, a price based on LRMC may fluctuate because transmission investment is lumpy, which would compromise the provision of a price signal that is durable over the long term.

15. An alternative to LRMC is long-run incremental cost (LRIC). In the context of exacerbators pay, LRIC is the additional cost of augmenting the network, over and above that already planned, because of an exacerbator's actions or inactions.

16. The Authority considers that exacerbators pay pricing approaches should be assessed according to the extent to which they promote the statutory objective with respect to elements of transmission pricing for which a satisfactory market-based approach has not been found. Further, any proposal to amend the TPM in order to implement exacerbators pay would need to comply with the Authority's Code amendment principles.

Beneficiaries pay

17. Applying a beneficiaries pay approach requires a robust method for identifying beneficiaries that can be applied consistently across the grid and over time. The benefits of improved investment efficiency and durability will be compromised if beneficiaries cannot be cost-effectively and clearly identified.

18. Ideally, the price that should apply to beneficiaries should reflect the lesser of the charge which will fully recover the costs of the grid being paid by beneficiaries and the

anticipated (*ex ante*) value to them from the services provided by the grid. Cost allocation to beneficiaries should be fixed at a point in time, as this avoids the problem of the method of cost allocation influencing their use of the asset.

19. Determining the extent to which a party benefits from the grid involves considering the costs of any alternatives available because the benefit cannot exceed the cost of its next best alternative. Charging a beneficiary more than it is willing to pay may provide incentives for parties subject to beneficiaries-pay charging to disconnect from the grid, which may be inefficient. An illustrative example set out in Appendix B suggests that this may be an issue for major industrial customers.

Alternative charging options

20. If it is not possible to achieve a market-based charging method or charging based on exacerbators or beneficiaries pay, an alternative charging option may need to be implemented. Any such option would need to:

    (a) limit the distortion in use of the grid resulting from the imposition of charges; and

    (b) ensure the costs of providing the grid are fully covered, so future investment in the grid is not inhibited by investors in the grid fearing they will not receive a return on their capital.

21. Approaches that would fit into a regime that would meet these requirements include:

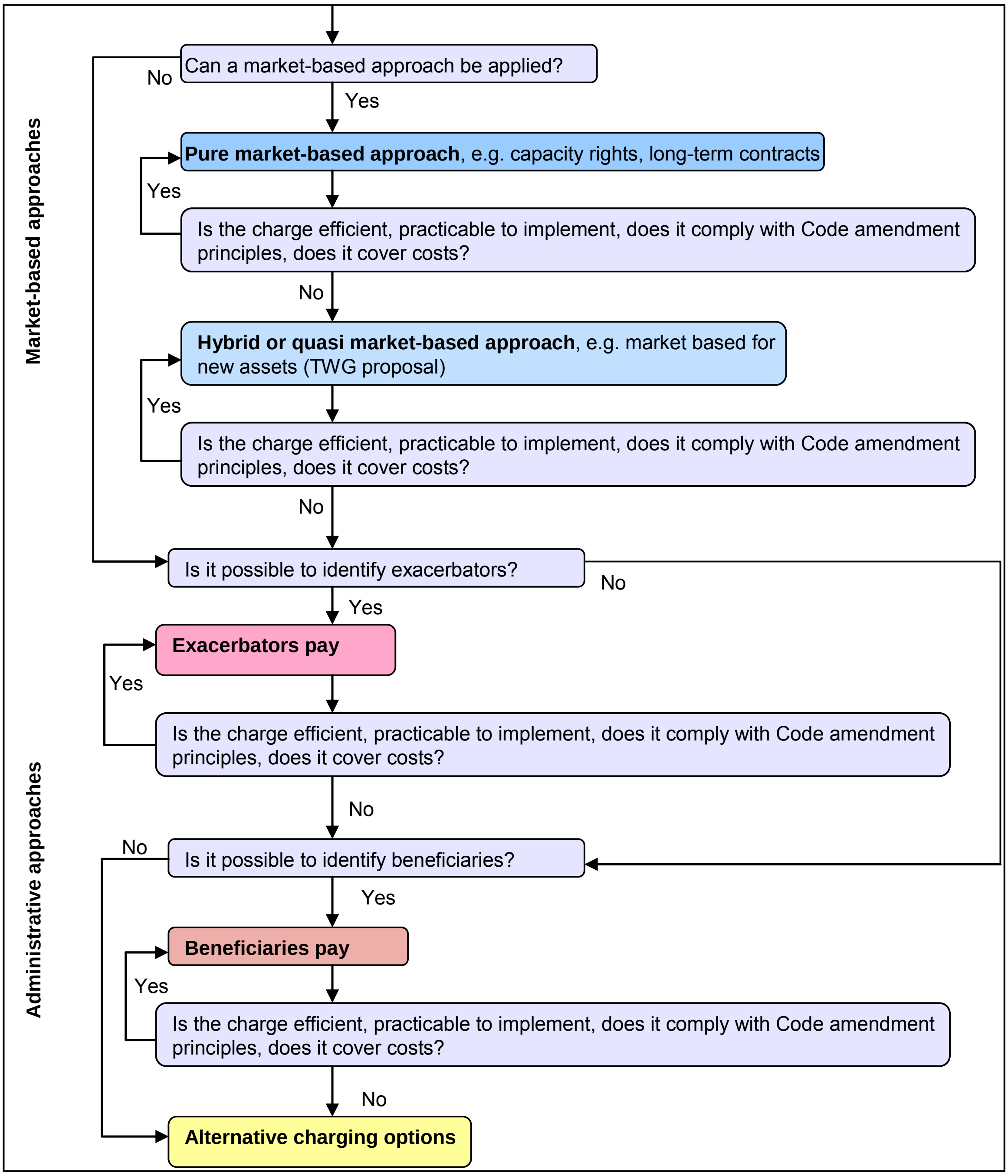
    (a) setting the charges so full coverage of costs will occur, but levying the charges on an ‘incentive-free’ basis; that is, on a basis unrelated to the current level of usage of the grid; and

    (b) setting the charges so full coverage of costs will occur, but spread out evenly across as broad a base as possible, so the amount per unit of the base upon which they are levied is low, i.e. a postage-stamp approach. This should restrain the impact the charges have on usage and hence on the resulting inefficiency.

22. The interconnection charge in the current TPM, which is applied on a uniform postage-stamp rate to all off-take customers on the basis of their usage relative to regional coincident peak demand (RCPD), is an example of this kind of charge.

23. The flowchart set out in Figure 1 outlines and summarises the Authority’s preliminary view as to the decision-making process and economic framework it should consider.

Figure 1: Preliminary view of decision-making and economic framework for transmission pricing



Glossary of abbreviations and terms

AC	Alternating Current
Act	Electricity Industry Act 2010
Authority	Electricity Authority
CGE	Computable General Equilibrium (models). CGE models are economic models that use actual data to estimate the economic impact of changes in policy, technology or other external factors
Code	Electricity Industry Participation Code 2010
Commission	Electricity Commission
EGEC	Electricity Governance Establishment Committee
GEM	Generation Expansion model
HAMI	Historical Anytime Maximum Injection
HVDC	High Voltage Direct Current
ICP	Installation Control Point
LNI	Lower North Island
LSI	Lower South Island
NPV	Net Present Value
PDP	Prudent Discount Policy
PF	Power Factor
Postage-stamp charge	Flat-rate charge on off-take customers
RCPD	Regional Coincident Peak Demand
Review	Wide-ranging review of the options for the allocation methodology for transmission costs
Rules	Electricity Governance Rules 2003
SRC	Static Reactive Compensation
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
TWG	Transport Working Group of the Electricity Governance Establishment Committee
UNI	Upper North Island
USI	Upper South Island

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1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 The Electricity Authority (Authority) is responsible under section 16(1)(b) of the Electricity Industry Act 2010 for making and administering the Electricity Industry Participation Code 2010 (Code), which includes, as Schedule 12.4, the Transmission Pricing Methodology (TPM).

1.1.2 The TPM sets out the arrangements for allocating total recoverable transmission costs to designated transmission customers. The Commerce Commission is responsible for regulating Transpower's total recoverable transmission cost requirement.

1.1.3 The Authority is reviewing the TPM to determine whether it is consistent with its statutory objective, which is:

> "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers."[2]

1.1.4 Currently, transmission services cost around $700m annually. These costs will rise to over $1bn per annum over the next ten years as increased investment in the transmission grid is undertaken and the costs recovered.

1.1.5 The level and structure of transmission charges under the TPM will affect the use of, and investment in, the grid, and have flow-on effects for operation and investment in generation, demand-side management and other sectors of the economy.

1.2 Background

1.2.1 The current TPM has been in place since 2008, but is largely based on the TPM that was developed by Transpower in the late 1990s.

1.2.2 The Electricity Commission (Commission) commenced a review of the TPM in February 2009 in response to requests by South Island generators. They are principally concerned about the allocation to them of the costs of the High Voltage Direct Current (HVDC) link between the North and South Islands. Some generators have long objected to this aspect of the TPM. In 2008 the Commission approved a very significant replacement investment and upgrade of this connection. This will increase the charges for the link considerably.

[2] Electricity Industry Act 2010, section 15.

1.2.3 The Commission undertook analysis of issues and options for transmission pricing and twice consulted with participants and consumers in October 2009 and July 2010.

1.2.4 Following the establishment of the Authority on 1 November 2010, the Authority continued the Review.

1.2.5 In January 2011, the Authority Board established a Transmission Pricing Advisory Group (TPAG), consisting of electricity industry participant representatives and customers, to provide advice and recommendations on a preferred option for transmission pricing.

1.2.6 TPAG was unable to reach a consensus on key aspects of the current TPM, such as charging for the HVDC link and so did not make firm recommendations on these aspects.

1.2.7 TPAG presented its analysis to the Board in early September 2011.[3] Since then, the Authority has been reviewing TPAG's work and undertaking additional analysis.

1.3 Purpose of this paper

1.3.1 The purpose of this paper is to consult with participants and persons that the Authority thinks are representative of the interests of persons likely to be substantially affected by the Review of the TPM.

1.3.2 This is important at this stage of the Review given that:

(a) there has been a change in the oversight of the Review from the Commission to the Authority, and with this a change in statutory objective;

(b) TPAG was unable to reach a consensus and make a recommendation on key aspects of transmission pricing; and

(c) in the Authority's view, while TPAG advanced to a significant degree the analysis of the TPM:

 (i) TPAG did not provide a comprehensive and durable framework for making decisions about the TPM; and

 (ii) consideration of the TPAG report in the light of information about the price paid for the sale of Whirinaki power station raises issues around efficient transmission pricing in New Zealand that the Authority should consider.

1.3.3 This paper sets out and invites submissions on:

3 TPAG's Report to the Authority is available at: http://www.ea.govt.nz/document/14915/download/our-work/advisory-working-groups/tpag/ (hereinafter referred to as the TPAG Report).

(a) the application of the statutory objective with respect to the TPM; and

(b) the economic framework that the Authority proposes to use to assess alternative TPMs.

1.3.4 The process of reviewing the TPM has been under way for several years. The Authority's intention is to institute a comprehensive and durable framework in which decisions about transmission pricing can be made.

1.3.5 The Authority recognises that there has been significant analysis by the Commission, TPAG and interested parties during the Review, which has improved understanding of the issues with the current methodology and the possible alternatives. The Authority will consider this analysis within the context of the decision-making and economic framework it adopts following consultation on this paper.

1.4 Next steps

1.4.1 Following consideration of submissions on this paper, the Authority will finalise its decision-making and economic framework and use this to assess transmission pricing methodology options.

1.4.2 For any aspect of the TPM for which the Authority's preferred option is an alternative to the status quo, the next step will be to prepare and release an issues paper as required by clause 12.81 of the Code. This will include the draft guidelines and process that Transpower must follow in developing a new TPM, as required by clause 12.83 of the Code.

1.4.3 In accordance with Part 12 of the Code, the Authority will then consider submissions on that issues paper and determine the process that Transpower must follow to develop a revised TPM, and the guidelines that Transpower must follow in preparing a revised TPM (clauses 12.82 and 12.83 of the Code).

1.4.4 Despite the Authority not being required to consult on a decision to retain the status quo, if the status quo is the Authority's preferred option the Authority will release for consultation a paper explaining its proposed decision. The paper would seek feedback on the Authority's analysis and preliminary conclusions.

1.5 Submissions

The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with 'Consultation Paper—Decision-making and economic framework for transmission pricing methodology review' in the subject line.

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

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

Fax: 0-4-460 8879

1.5.1 Submissions should be received by 5:00pm on Friday 24 February 2012. Please note that late submissions are unlikely to be considered.

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

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

2. An overview of the current transmission pricing methodology

2.1 The current TPM

2.1.1 Under the current TPM, transmission customers face the following charges:

(a) charges for connection assets that recover the costs of dedicated AC assets connecting a designated transmission customer to the grid. Distribution companies, generators and large consumers connected directly to the grid pay these charges. Charges for connection assets currently amount to around $120m per year;

(b) an interconnection charge that recovers the cost of the rest of the AC transmission system. This charge is paid by large consumers directly connected to the grid and by distribution companies. Transpower allocates the interconnection charge to distributors and large consumers based on various measures of the customer's contribution to regional coincident peak demand (RCPD). There are four regions: Upper and Lower North Island and Upper and Lower South Island. Interconnection charges currently amount to around $450m per year; and

(c) an HVDC charge to recover the costs of the HVDC link between the North and South Islands. This charge is allocated to South Island generators based on their share of peak injections in the South Island – called HAMI, or historical anytime maximum injections. HVDC charges currently amount to around $120m per year.

2.1.2 An integral part of the current TPM is the Prudent Discount Policy (PDP). The purpose of the PDP is to help ensure the TPM does not provide incentives for the uneconomic bypass of existing grid assets. It does this by providing discounts to customers facing such incentives. The discounted sums are recovered from other transmission customers by Transpower in accordance with the TPM.

2.1.3 Figure 2 shows the basis on which charges are determined and the approximate relative revenue in relation to each charge for 2011/12.

Figure 2: Transmission charges and customers

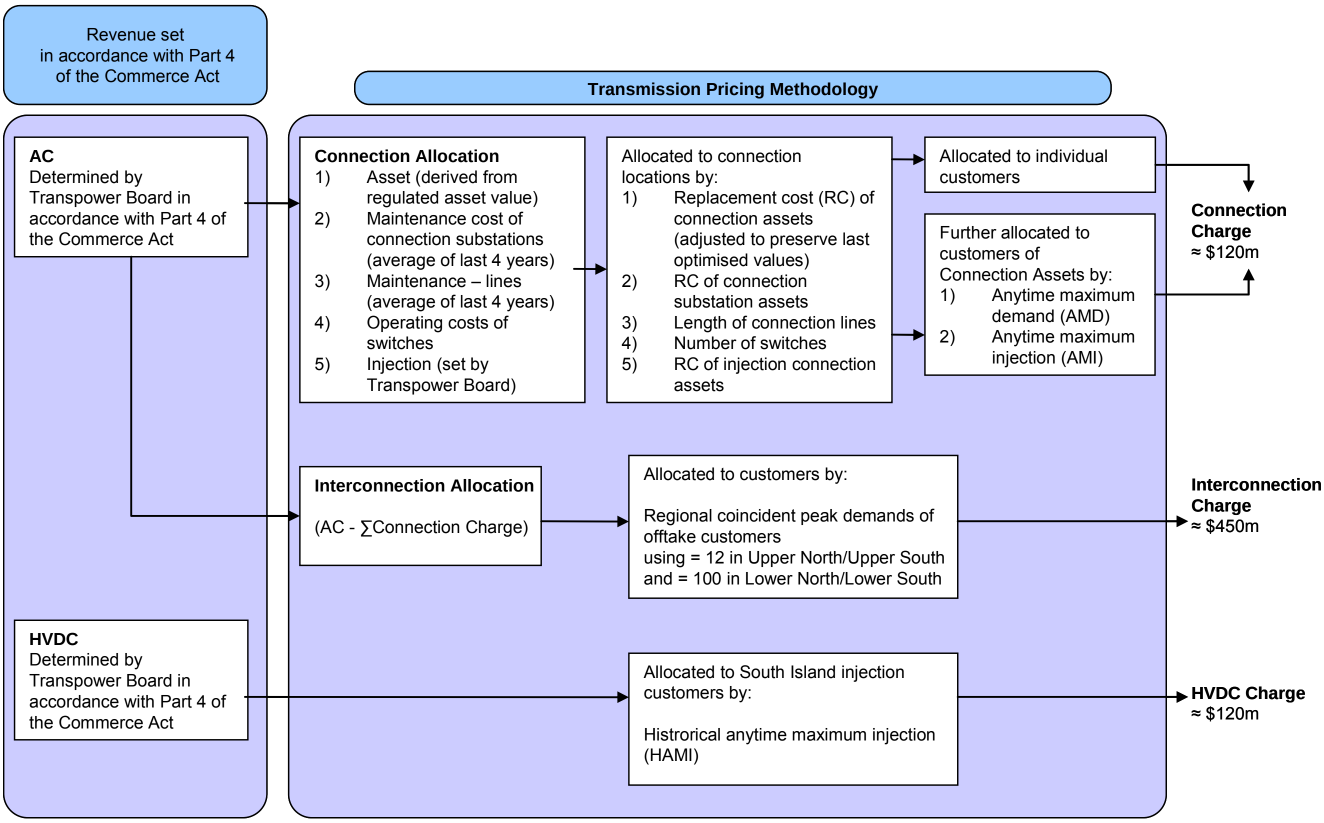
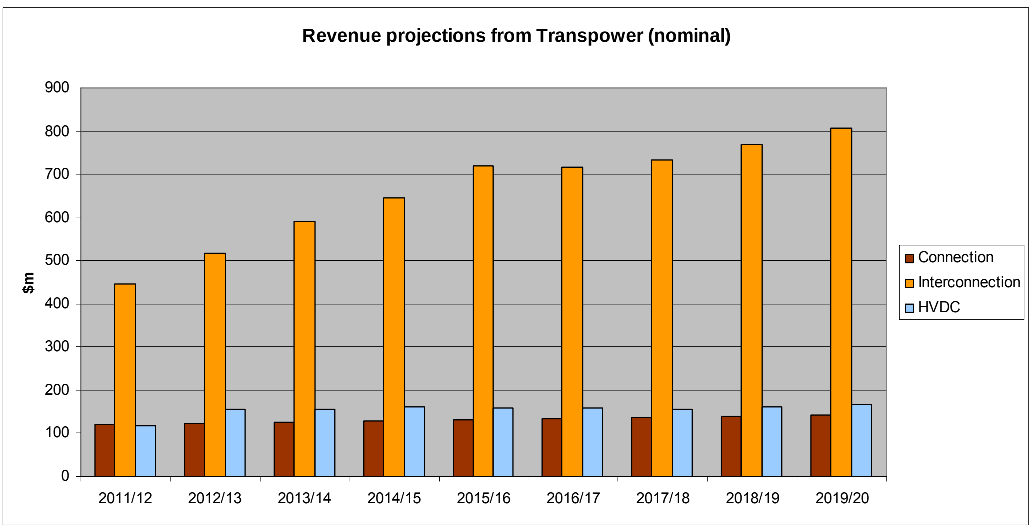


Figure 3 shows the projected growth of revenue in relation to each charge until 2020.

Figure 3: Components of TPM and projected growth to 2019/2020[4]



4 Source: Transpower, November 2010.

2.1.4 These charges, and potential problems with them, are discussed below. In addition, problems with the existing arrangements for static reactive compensation are discussed as changes to the TPM could resolve these problems.

2.2 Connection charges: overview

2.2.1 Transpower recovers its costs of providing connection assets by three means:[5]

(a) connection charges set out in the TPM and made up of an asset component, maintenance component, operating component and, for injection customers only, an injection overhead component (the portion of AC overhead costs recovered from injection customers);

(b) new investment contracts negotiated directly between Transpower and its customers that specify the replacement cost of the assets to be used in calculating the asset component of the relevant connection charges; and

(c) input connection contracts that Transpower has negotiated with some of its generation and directly connected customers as an alternative to levying them the standard connection charges according to the TPM.

2.2.2 In most cases, connection assets are used by a single party, but there are a very few cases where two or more parties share connection assets. The current TPM allocates the connection charge for these shared connection assets in proportion to each customer's share of anytime maximum injection or demand, as it is peak injection or demand that determine the size of the connection assets needed.

2.2.3 Although connection charges seem straightforward, the definition of connection assets that differentiates them from interconnection assets is potentially contentious. A deep connection approach seeks to identify assets in the grid that would not be required, or would need less capacity, if the connection party did not exist. In practice, some assets arguably provide both connection and interconnection benefits, making it difficult to 'draw the line'. The opposite approach is to adopt a shallow connection definition, which defines connection assets to be only the assets most immediately used to connect to a customer.

2.2.4 The depth of the connection/interconnection boundary can influence efficient investment; the deeper the allocation of assets to individual customers, the more significant the locational signal for investment from transmission charges. On the other hand, a deeper connection/interconnection boundary can result in inefficient costs as participants seek to avoid or contest connection charges.

[5] Transpower New Zealand, *Transmission Pricing Methodology*, June 2007, pp. 16-23.

2.2.5 In general, although concern has been expressed by some parties about the inclusion of particular assets as connection assets for which they are required to pay, the charges for connection assets have been the least contentious of the components of the current TPM.

2.3 Interconnection charges: overview

2.3.1 Distributors and large consumers directly connected to the AC grid pay for interconnection assets. The interconnection assets are those beyond the connection boundary that are part of the interconnected AC grid.

2.3.2 It is harder to determine which party is using any particular asset in the interconnected grid as the flow of electricity across the grid from any one generation unit depends on the pattern of injections by other generators and demand by off-take customers across the grid. No individual generator controls where the electricity they produce flows on an AC network in real-time, and neither does Transpower. The same applies to the electricity consumed by customers.

2.3.3 Investment in interconnection assets typically exhibit significant economies of scale: if a new interconnection circuit is going to be installed it is typically cost effective to install far greater capacity than is needed for the immediate future, if reasonably rapid growth in demand is forecast. The cost of regularly increasing interconnection capacity every few years is generally greater than building one with sufficient capacity for the next 30 – 40 years.

2.3.4 This combination of features – large economies of scale and multiple paths for flow – makes it harder to allocate the costs directly to groups of customers or to have a market-based solution for investment and pricing interconnection services.

2.3.5 The generally accepted practice is to adopt a cost-reflective approach to interconnection pricing. Doing this would involve charging interconnection prices that reflect the impact that each interconnection user has on interconnection capacity, which will include the cost of augmenting multiple segments of the interconnection system.

2.3.6 Under this approach, consumers choosing to locate far away from major sources of generation pay higher interconnection charges than consumers locating close to generation. Similarly, generators choosing to locate their new plants far away from major demand centres pay higher interconnection charges than those locating close to load.

2.3.7 However, the interconnected nature of the assets mean that it is not straight-forward to uniquely associate peak injections or peak demand with interconnection capacity. Sometimes a peak injection will constrain interconnection capacity and at other times it will not, and altering one component of the system can alter the power flows on all other components.

2.3.8 In some jurisdictions, locational-based charges are designed to approximate the appropriate cost allocations and to signal future transmission costs. Depending on the network and market arrangements these charges may improve dynamic efficiency. However, there are trade-offs. A charging regime which includes an 'approximate' locational signal to generators can carry the risk of either under- or over-signalling and is likely to influence not only participants' investment decisions, but also their day-to-day use of the grid. This can lead to inefficient scheduling and dispatch of generators or inefficiently reduce use of existing grid assets.

2.3.9 Given these difficulties, and the shared nature of interconnection services, many countries have chosen the pragmatic approach of recovering interconnection costs via a flat-rate charge on users. In New Zealand, this is achieved in the current TPM with a flat-rate charge on Transpower's off-take customers (distributors and consumers directly connected to the grid), based on various measures of peak demand.[6]

2.3.10 The flat rate is often referred to as a postage-stamp rate, because the rate is the same regardless of where the off-take customer draws electricity from the grid. That is, the price for interconnection services is the same throughout New Zealand in the same way that the standard letter rate set by NZ Post is the same regardless of where a letter is sent to in New Zealand.

2.3.11 A primary issue with postage stamp pricing internationally is that it does not provide price signals to encourage generators or load (in particular, load that is electricity intensive) to make efficient location decisions – that is, to take into account the cost of transmission when deciding where to locate their plants.

2.3.12 In countries such as New Zealand that have adopted locational marginal pricing (LMP) or nodal pricing, however, this may be less of an issue as the spot market provides some of the needed locational price signals. Connection charging also provides some locational signalling by ensuring customers pay for dedicated assets; the greater the depth of the connection boundary the greater the level of locational signalling provided.

6 The interconnection grid is divided into four regions: Upper North Island (UNI), Lower North Island (LNI), Upper South Island (USI) and Lower South Island (LSI). Peak demand in the UNI and USI regions is measured on the basis of the twelve highest levels of regional demand levels each preceding year. The same approach is adopted for the LNI and LSI, except that the 100 highest demand peaks are used to measure peak demand. Off-take customers in all regions are charged the flat rate on their share of the total regional demand for each peak period.

2.3.13 An issue often raised with New Zealand's postage stamp interconnection charge is that it results in customers in areas not needing increases in capacity contributing to fund expansions in areas, like Auckland, where capacity is being increased. This, it is claimed, leads to excessive requests for expansion of grid facilities as those receiving the services the facilities will bring do not bear all the costs of providing them. As a result, there have been periodic calls for more targeted regional-based interconnection charges, and for the adoption of "but-for" charging. Under "but-for" charging, the parties whose decisions are responsible for investment in the grid are required to pay for it (on the basis that the investment would not have been required "but for" their decisions).

2.4 HVDC charges: background and issues

2.4.1 The costs of the HVDC have been allocated under the promulgated TPM entirely to South Island generators since the mid to late 1990s. At the time when this allocation was introduced, the review and development of the TPM was Transpower's responsibility.

2.4.2 Transpower's decision to recover all costs associated with the HVDC link from South Island generators was partly based on its view that the bulk of benefits from the existence of the HVDC link accrue to the South Island generators through access to higher North Island prices.[7] Other factors behind Transpower's decision were that it considered that this was consistent with allocative and dynamic efficiency because in its opinion:

(a) it was unlikely that additional generation would be built in the South Island for some considerable period of time, so levying the charge on South Island generators would not influence investment decisions and this would be dynamically efficient;

(b) the other major group of beneficiaries was North Island consumers, but to levy a charge on them would alter their consumption of electricity and use of the grid, and this would be inefficient; and

(c) levying the charge on South Island generators through a charge based on their historical anytime maximum injections would not materially impact the wholesale price of electricity, given that this was based on the offers of the marginal generators. As a result, the recovery of sunk costs in the grid would not impact on electricity consumption and this would also be efficient.

2.4.3 On the establishment of the Electricity Commission in 2003, the Commission was required to develop Guidelines for the development of the TPM by Transpower.

[7] *Pricing for Transmission Services. Introduction to the pricing methodology to be applied from 1 October 1996*, Transpower.

The Commission maintained the allocation of the costs of the HVDC link on South Island generators in its 2006 decision on the TPM Guidelines.[8]

2.4.4 In the current TPM, the HVDC charge is levied on the owners and operators of South Island generation that is directly connected to the grid or to a local network to which South Island generation is connected, either directly or indirectly. The charge is allocated among liable parties *pro rata* on the basis of their share of the historical anytime maximum injection (HAMI) of all South Island generation. The HAMI at a location is calculated as the highest annual average of the 12 highest injections at the location during the previous five pricing years.

2.4.5 The Commission's decision was a complex one on a long standing issue and the Commission was required to balance a wide range of conflicting interests, including diametrically opposed and strongly held views about who should pay for the HVDC link.[9] These opposing views were broadly:

(a) the HVDC link is essentially a connection asset and parties benefiting from it should pay for it, just as connection customers pay for connection services, and the beneficiaries of the link are the South Island generators that inject into the grid; and

(b) the HVDC link is essentially an interconnection asset and its costs should be recovered evenly from Transpower's off-take customers like other interconnection assets. The simplest way to do this is to combine the HVDC and interconnection costs and collect the total revenue through the postage-stamp regime on off-take customers.

2.4.6 Those opposed to the allocation of the costs of the HVDC link to South Island generators have argued in various fora:[10]

(a) South Island generators are not the only significant beneficiaries of the HVDC link. They point to flows occurring in both directions and argue North Island consumers benefit through lower prices as do South Island consumers from the increased security of supply they receive from access to North Island generation in dry years;

(b) the structure of the charge confers a competitive advantage for the development of new South Island generation on large incumbent South Island generators, specifically Meridian Energy, and this leads to productive inefficiency in generation investment;

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

9 *Explanatory Paper – Commission's Final Decision HVDC Transmission Pricing Methodology, March 2006.*

10 See TPAG Report, Appendix C.

(c) the charge imposes a competitive disadvantage on new South Island generation relative to new North Island generation and in the long run this will increase the cost of electricity in New Zealand because the most efficient plants will not be built; and

(d) the structure of the charge discourages the operation of South Island generation plant at full capacity because a short-term peak will increase the plant's HAMI, and hence its liability for HVDC charges, for five years and this is inefficient.

2.4.7 The charges for the HVDC link have undoubtedly been the most controversial element of the current TPM.

2.5 Prudent discount policy: overview

2.5.1 The PDP is often overlooked in discussions of the TPM but it is an integral part of the cost allocation regime for grid assets. The purpose of the PDP as set out in clause 36 of Schedule 12.4 of the Code is to help ensure that the TPM does not provide incentives for the uneconomic bypass of existing grid assets. Customers are able to receive a discount from the TPM charges they would otherwise be liable for if they can identify an 'alternative project' it would be economic for them to implement, given the TPM, but which would be uneconomic for the country as a whole, given Transpower's economic costs of providing existing grid assets.

2.5.2 In order to receive a discount a transmission customer must satisfy Transpower, or an independent expert, that its alternative project is technically, operationally and commercially viable and has a reasonable prospect of being able to be successfully implemented.

2.5.3 If a prudent discount application is successful, the discount is the difference between what the customer's costs would be if the alternative project proceeded and what its charges would be under the TPM without it. The customer pays Transpower what its costs would be if it adopted the alternative. The balance of the charge that would have otherwise been levied on the customer under the TPM is allocated to other parties in accordance with the TPM. The duration of a prudent discount agreement is the lesser of the remaining economic life of the grid assets that are affected by the agreement, or 15 years.

2.5.4 The Authority understands that there have been several successful prudent discount applications.

2.5.5 The main rationale for the PDP is to forestall the construction of lines to embed load in distribution networks when it would be more efficient for the load to be connected directly to the grid.

2.5.6 The inclusion of a PDP in the TPM has never been very contentious. Most parties have recognised that it is in the long term interests of the economy that inefficient grid bypass is avoided. There have, however, been concerns about the costs of preparing the material to make an application and the detail of the policy. For example, under the current TPM, a prudent discount agreement cannot be implemented if the alternative project relates to proposed new generation. This exclusion, together with the 15-year maximum term for an agreement, limits the practical application of the PDP.

2.6 Static reactive compensation: overview

2.6.1 The current arrangements for voltage support at grid exit points require that off-take customers meet the power factor[11] requirements that are set out in the Connection Code. In the Upper North and South Island regions the power factor requirement is unity. In the Lower North and South Islands the requirement is 0.95 lagging.

2.6.2 The rationale for the unity power factor requirement is that provided the off-take power factor is close to unity there is minimal requirement for the grid owner to provide static reactive compensation (SRC) equipment.

2.6.3 In practice, however, it is impracticable for off-take grid customers to comply with the unity power factor requirement in the Upper North and South Island regions at reasonable cost. It is also impracticable to enforce breaches by off-take customers of the power factor requirements in the Connection Code. The attempt to minimise expenditure on SRC by requiring parties to act so that it is not required is inconsistent with promoting the efficient level of investment in such equipment; the efficient level is not zero.

2.6.4 Although payment for SRC equipment connected to the grid is not an explicit line item in the current TPM, if an explicit charge were introduced, as TPAG recommended,[12] it would be. The subject is therefore relevant to the Authority's decision-making and economic framework for review of the TPM.

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[11] The power factor (PF) is a measure of the efficiency of the transmission of power in a network. The PF is the ratio between the real power and apparent power flowing at a point in a network. The highest PF is equal to 1.0 (or unity) and represents the state where there is only real (useful) power and no reactive power flowing past the measurement point.

[12] TPAG Report, p.11.

3. Decision-making framework

3.1 Regulatory framework

3.1.1 The TPM is a schedule to Part 12 of the Code and so any change to the TPM requires an amendment to the Code. There are also requirements in subpart 4 of Part 12 of the Code concerning the TPM. These requirements specify the process for development and approval of a TPM and include the development of a set of guidelines that Transpower must follow in developing a proposed TPM.

3.1.2 Under both these sets of requirements, the TPM must be consistent with the Authority's statutory objective.

3.1.3 The Authority's Consultation Charter[13] establishes the Code amendment principles which the Authority will adhere to when considering Code amendments.

3.2 Statutory objective

3.2.1 The Authority's statutory objective is:

> "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers."[14]

3.3 Interpretation of statutory objective

3.3.1 The Authority published its interpretation of its statutory objective in February 2011.[15]

3.3.2 In summary, the Authority interprets its statutory objective as requiring it to exercise its functions set out in section 16 of the Act in ways that, for the long-term benefit of electricity consumers:

(a) facilitate or encourage increased competition in the markets for electricity and electricity-related services, taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in those markets;

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[13] Required by section 41 of the Act and available at: http://www.ea.govt.nz/our-work/consultations/corporate/consultation-charter/.

[14] Electricity Industry Act 2010, section 15.

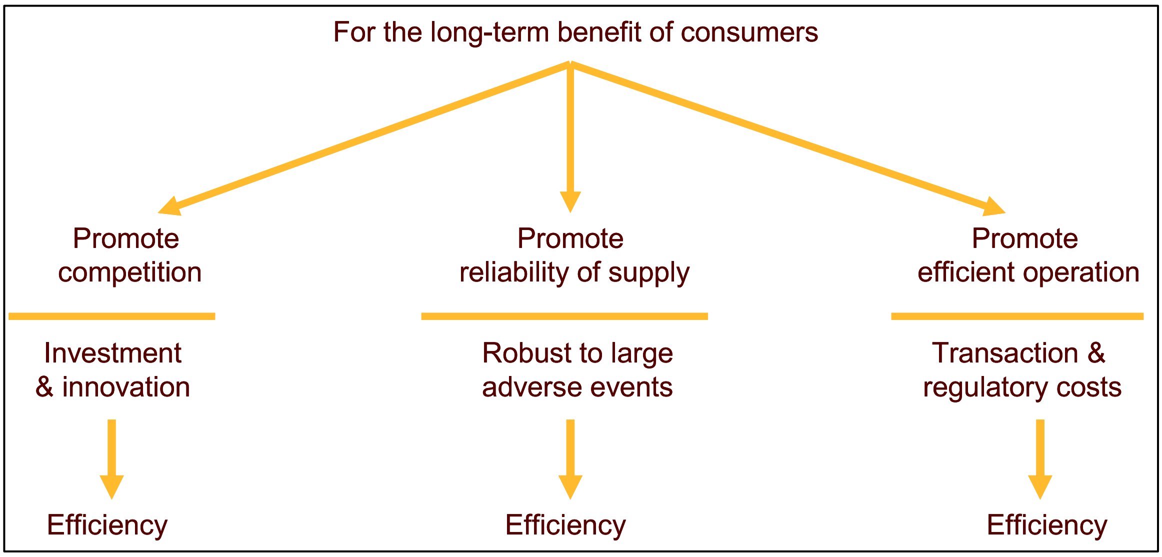
[15] Electricity Authority, *Interpretation of the Authority's statutory objective*, 14 February 2011. Available at: http://www.ea.govt.nz/document/12803/download/about-us/documents-publications/foundation-documents/.

(b) encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst being robust to adverse events; and

(c) increase the efficiency of the electricity industry, taking into account the transaction costs of market arrangements and the administration and compliance costs of regulation, and taking into account Commerce Act implications for the non-competitive parts of the electricity industry, particularly in regard to preserving efficient incentives for investment and innovation.

3.3.3 Figure 4 summarises the Authority's interpretation of its statutory objective and how, ultimately, each limb of the statutory objective is about promotion of efficiency as the means to achieve the long-term benefit of consumers.

Figure 4: Summary of interpretation of statutory objective



3.3.4 The Authority's *Interpretation of its statutory objective* provides more detail on how the Authority interprets key elements, and it is worth highlighting some aspects of this: the treatment of wealth transfers, and the in-depth interpretation of the three limbs of the statutory objective: competition, reliability and efficiency. References given are references to the Authority's interpretation of its statutory objective.

Wealth transfers

3.3.5 With respect to wealth transfers, importantly "*the Authority considers the net effects on electricity consumers and assesses the benefits to them in aggregate. This means that in virtually all circumstances, only the efficiency gains of an initiative should be treated as benefiting consumers, with wealth transfers* *excluded because they 'net off' among all electricity consumers once indirect wealth effects are taken into account*".[16]

Competition

3.3.6 Competition in the electricity industry is interpreted to mean workable or effective competition in regard to buying and selling electricity and where possible in electricity-related services, such as ancillary services, and transmission and distribution services (paragraph A19, Appendix A, *Interpretation of the Authority's statutory objective*). From an aggregate consumer perspective, workable competition delivers benefits to consumers by placing pressure on firms to set their prices close to their marginal cost of supply (paragraph A22).

3.3.7 In particular, under workable or effective competition, the actions of competitors and potential entrants ensure that a market participant acts efficiently. As a result, no single participant is able to *sustainably* charge prices in excess of marginal cost, or restrict supply. Under workable competition, however, there may be periods when a firm is able to temporarily set prices in excess of marginal cost because of superior performance or innovation. Over time, though, the ability to do this will be competed away, and the benefits in terms of both price and service quality will be shared with consumers.

3.3.8 The Authority interprets competition for the benefit of electricity consumers to mean the efficiency benefits of competition. This interpretation excludes wealth transfers from the calculation of benefits to consumers, but it includes any efficiency effects that may arise from wealth transfers (paragraph A25). However, if wealth transfers seriously undermine confidence in the pricing process or in the electricity industry more generally, then that can inhibit efficient entry and investment decisions and these dynamic efficiency effects should be taken into account when evaluating proposals (paragraph A31(b)).

Reliability

3.3.9 The benefits of reliable supply are the avoided costs of supply interruptions and quality degradation, and the avoided costs of under-investment by electricity users arising from investor uncertainty. Conversely, the costs of reliable supply are the costs of obtaining, operating and maintaining transmission, distribution and generation resources, and additional demand response capability to cover short and long-term risks in the power system (resource costs) (paragraph A37).

3.3.10 Reliable supply is efficient when the marginal benefit of increased security and reliability equals the marginal cost of achieving it. The Authority, therefore, interprets reliable supply for the long-term benefit of consumers to mean the

[16] See paragraphs A5 to A10, Appendix A, *Interpretation of the Authority's statutory objective*.

efficient level of reliability, which occurs when the total of these costs is minimised.

3.3.11 As for efficiency and competition, this approach is an aggregate consumer interpretation of the benefits to consumers, which excludes wealth transfers to consumers. If direct wealth transfers were taken into account (but not indirect wealth transfers), then price reductions would be valued ahead of reliable supply, which the Authority does not believe was intended by the Act. Adopting an efficiency (i.e. aggregate consumer) approach achieves an even-handed treatment of resource costs versus avoided costs (paragraph A39).

3.3.12 The Authority interprets the phrase reliable supply for the long-term benefit of consumers to mean efficient levels of reliable supply where efficiency includes dynamic efficiency gains from adopting time-consistent arrangements – that is, arrangements that are robust to adverse events over the long term. In regard to minimising total costs, the Authority believes the potential costs of regulatory uncertainty and ad-hoc interventions should be taken into account in determining minimum total costs (paragraph A46).

Efficiency

3.3.13 The efficient operation limb of the Authority's statutory objective enables the Authority to take into account the transaction costs of market arrangements and the administrative and compliance costs of regulation, but also to take into account the incentives for efficient investment and innovation in the electricity industry, by both suppliers and consumers (paragraph A59).

3.4 Application of statutory objective to transmission pricing

3.4.1 Consistent with its interpretation of the statutory objective, the Authority takes the view that the framework for decision-making about options for the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers. This recognises that competition is an important tool to encourage efficient outcomes, and that measures that impact on reliability outcomes should encourage efficient trade-offs between the costs and benefits of reliability.

3.4.2 This overall efficiency refers to both efficient use of the grid and efficient investment in the electricity industry – the grid, generation and demand-side management:

(a) efficient use of the grid focuses on least cost production and charging customers the efficient marginal costs of production; and

(b) efficient investment focuses on the lowest cost development of the industry over time.

3.4.3 For the existing grid, increased usage involves little additional cost, as most costs are sunk. Therefore, efficient use requires that prices for the existing network should aim to recover costs in a way that does not discourage or alter use of the existing network.

3.4.4 However, where investment in the transmission system is required, the incremental or avoidable costs of additional usage are much higher. Under these circumstances, the focus should be on finding the lowest cost way of providing services. In some cases this aim may be promoted by investment in alternatives to transmission, such as generation and demand-side management options.

3.4.5 One way this can be done is by signalling future investment costs via transmission charges either to those participants whose behaviour influences the requirement for an activity ('exacerbators'), or to those participants who benefit from the investment ('beneficiaries'). However, charging on the basis of the incremental costs of expansion of capacity can conflict with charging so as not to discourage use of an existing asset; the dynamic and static efficiency aims can conflict. This conflict arises because the substantial economies of scale in transmission means it is difficult to set charges that align both static and dynamic efficiency aims.

3.4.6 In summary, the Authority's interpretation of the statutory objective with respect to transmission pricing involves consideration of the impacts of charges on the efficient use of the grid and efficient investment in the electricity industry as a whole.

Q1. Do you agree with the Authority's interpretation of its statutory objective with respect to transmission pricing? If you agree, please explain why. If you do not agree, please explain how you consider the statutory objective should be interpreted with respect to transmission pricing and the reasons for your interpretation.

3.4.7 Although the Authority's approach is to consider the impacts on the efficient use of the grid and investment, including investment in the overall electricity system, it is worth considering the three limbs of the statutory objective separately and examples of how transmission pricing can influence competition, reliability and operational efficiency.

3.4.8 Table 1 considers the application of the three limbs of the statutory objective to transmission pricing.

Table 1: The application of the statutory objective to transmission pricing

	Application to transmission pricing	**Examples of how transmission pricing can influence**
Competition	The allocation of transmission costs should support workable competition: • in generation, ancillary service, hedge and retail markets; and • between transmission investments and alternatives, such as demand-side management and generators, including peaking plants and back-up generators.	• If a transmission charge falls to a greater extent on one or more of a set of generators but not on others, this may distort competition in the development and emplacement of generation. • Transmission pricing has the potential to favour particular technologies or connection arrangements through the incidence and structure of charges. • A charge that falls solely on grid-connected generators may encourage generators to inefficiently embed within a network, although the PDP should provide some counterweight to this effect. • A charge that falls on direct connected customers with co-generation plants may be sufficient to encourage them to install back-up capacity and disconnect from the grid, even when this is inefficient from an economy-wide perspective.
Reliability	The allocation of transmission costs should support reliability investments where the marginal benefit of increased security and reliability equals the marginal cost of achieving it.	• Transmission pricing can signal the cost of investments to achieve reliability and encourage alternatives, such as demand side management, investment in peaking plants, and investment in back-up generation capacity. • Transmission pricing may also over signal the costs of investments to achieve reliability and encourage the adoption of a lower standard of reliability or alternatives, even when it is inefficient to do so from an economy-wide perspective.
Efficiency	Transaction, administrative and compliance costs	• A highly complex TPM can lead to high transaction and compliance costs.

	Application to transmission pricing	Examples of how transmission pricing can influence
	involved with any TPM should be at efficient levels. Transmission pricing should support • efficient use of the grid; and • efficient investment in the economy and power system as a whole, including transmission, generation and demand-side management.	• A TPM which provides locational signals or peak use signals can influence the short-term efficient dispatch of generation and use of sunk cost assets. • Allocation of costs to parties that influence the efficiency of outcomes can provide efficient signals for investment in the power system as a whole.

Q2. Do you agree with the above application of the three limbs of the statutory objective to transmission pricing? If not, why not, and are there other examples of how transmission pricing can influence competition, reliability and efficiency?

4. Economic framework for transmission charges

4.1 Introduction

4.1.1 Transmission services involve the transportation of a product (electricity) from its place of production (where the electricity is generated) to consumers directly connected to the grid and distributors that transport the product to the end consumers who want to use it. Transmission services are essentially transport services. This suggests it could be instructive for developing a robust TPM to consider how the costs of transport services are allocated when this is left to the market; what's the typical market solution?

4.1.2 The first thing to note is that there can be a difference between the party that actually pays the transport provider for the transport service and the party that bears the economic cost of that service. This is because transport costs can be passed between buyers and sellers through adjustments to the price of the good (or service) transported.

4.1.3 The short answer to the question of the allocation of transport costs by the market is that it depends on the state of competition in the market for the good or service. If the market is workably competitive, the extent to which an individual supplier more remote than some of its competitors can raise its price to cover its additional transport costs due to its more remote location is limited. If it attempts to do so, its customers will buy off alternative suppliers with lower transport costs.

4.1.4 In a workably competitive market most of the costs of transport above those incurred by the 'best' located supplier, are borne by producers. To illustrate, consider market gardeners in Oamaru supplying produce to Auckland consumers in competition with market gardeners in Pukekohe. Auckland consumers will not pay more for produce that is otherwise identical because it comes from Oamaru rather than Pukekohe, even though it has incurred significant additional transport costs.

4.1.5 Oamaru market gardeners bear the economic costs of getting their produce to the Auckland market above those incurred by the 'best' located alternative supplier. They will supply the Auckland market only if they have other advantages, such as cheaper land, relative to Pukekohe producers, for example. This allows them to compete successfully against producers located close to Auckland, despite the additional transport costs they incur.

4.1.6 On the other hand, if the market is not workably competitive, a large part of the transport cost may be borne by consumers. Consider the harvesters of mutton birds. The only place where production occurs is on small islands in Foveaux

Strait and the supply side is controlled by a closely related group of individuals. They will tend to incorporate into the price of mutton birds they send to Auckland the transport costs of getting the produce there. They will tend to sell at a cheaper price to people more close by. Similarly, vineyards selling wine by mail order often pass some of their transport costs on to customers through a distance related charge for delivery. The price they charge for the wine is usually standard irrespective of the location of the customer. They are able to do this because they know their delivered price will still be better than the local retail price of the product to the consumer; they have some level of buffer against their competition.

4.1.7 Long-term contracts are sometimes a key feature of transport pricing arrangements. Producers sometimes negotiate long-term contracts with transporters when they have limited choice of transporters and the producer has substantial investments in their own facilities that are costly to shift if transport prices rise.

4.1.8 Long-term contracts typically require the producer to bear the costs of transport but protect it from opportunistic behaviour by the transport provider to raise prices and charges and take advantage of the producer's limited alternatives and difficulty to relocate.

4.1.9 Instances of a consumer entering into a long-term contract for transport services are very rare. If they are concerned about supply costs, consumers usually prefer to enter into a contract with the producer for a price for the product on a delivered basis. This is because a consumer with a long-term contract for transport services without an agreement with the producer about price would be vulnerable to opportunistic pricing by the producer taking advantage of them being 'locked-in' to payment for transport services. If the market is workably competitive, the long-term agreement with the producer for supply, inclusive of delivery costs, will only reflect the delivery costs of the 'best' located producer. Otherwise, the consumer would contract with this party and avoid the additional transport charges.

4.1.10 Provided the transport market is workably competitive it forces trucking businesses to set their prices for a service (e.g. Oamaru to Auckland) at the level that just covers the additional cost of adding another truck to the service, including the cost of additional drivers and fuel – the short run marginal cost (SRMC). When demand is particularly low, such that trucking businesses have spare capacity, they may lower their prices to the variable costs of their business, but in normal demand situations they will set their prices to a level that just recovers all their costs.

4.1.11 The pricing structure for standard transport services when there is workable competition promotes three sources of efficiency:

(a) Productive efficiency: the efficient production of transport services or otherwise new entrants with lower costs will enter or threaten to enter the market at lower prices and take away business from other producers if their costs remain higher;

(b) Allocative efficiency: the efficient use of the transport service, as producers and consumers will transport their goods only when the benefits of transporting exceed the costs of transport; and

(c) Dynamic efficiency: efficient investment decisions as:

  (i) Consumers and producers face price signals that ensure they take into account the cost of transport when deciding where to locate their next plant and/or expand existing plant; and

  (ii) Trucking businesses face price signals that ensure they only add capacity to their business when consumers are willing to pay for it.

4.1.12 In short, in a workably competitive market, which is the Authority's benchmark market structure, most of the costs of transport services above those incurred by the 'best' located supplier, are borne by producers, not consumers. This is the case whether the transport service is provided on an ad hoc or casual basis, or as a result of a long-term contract.

4.1.13 This arrangement is generally consistent with the efficient use of transport services, their efficient operation and efficient investment in transport services, by producers and consumers. In other words, this arrangement satisfies the conditions the Authority is seeking in order to meet its statutory objective.

4.1.14 This analysis suggests that if the market is workably competitive and the market determines the allocation of the costs of transmission the likely outcome is that most of the costs of transmission above those incurred by the 'best' located generator, would be borne by generators, and not consumers.

4.2 Pricing: Market-based approaches

4.2.1 One of the attractions of trying to use market-based approaches to set prices is that the outcomes of markets tend to be efficient in regards to use and investment. This is because it is in the interests of all parties buying and selling in the market place to seek efficiency gains whenever and wherever possible, and there is no regulator, or other party, stopping them from achieving the gains.

4.2.2 This expectation holds provided buyers or sellers are not able to exercise market power; provided the market is at least workably competitive. Another requirement is that externalities, i.e. variances between the social costs of an activity and the costs facing decision makers about the activity, are able to be safely ignored, or they can be effectively 'internalised' to the decision makers.

4.2.3 A tendency to promote efficiency is not the only potential advantage of market-based arrangements for setting grid charges. They also tend to generate less controversy than administered charges and, as a result, can be more durable and sustainable. Lobbying about charges derived from or based upon the outcomes of market-based interactions between buyers and sellers is unlikely to alter the outcome but those setting administratively set charges – the alternative approach – are more susceptible to this kind of activity.

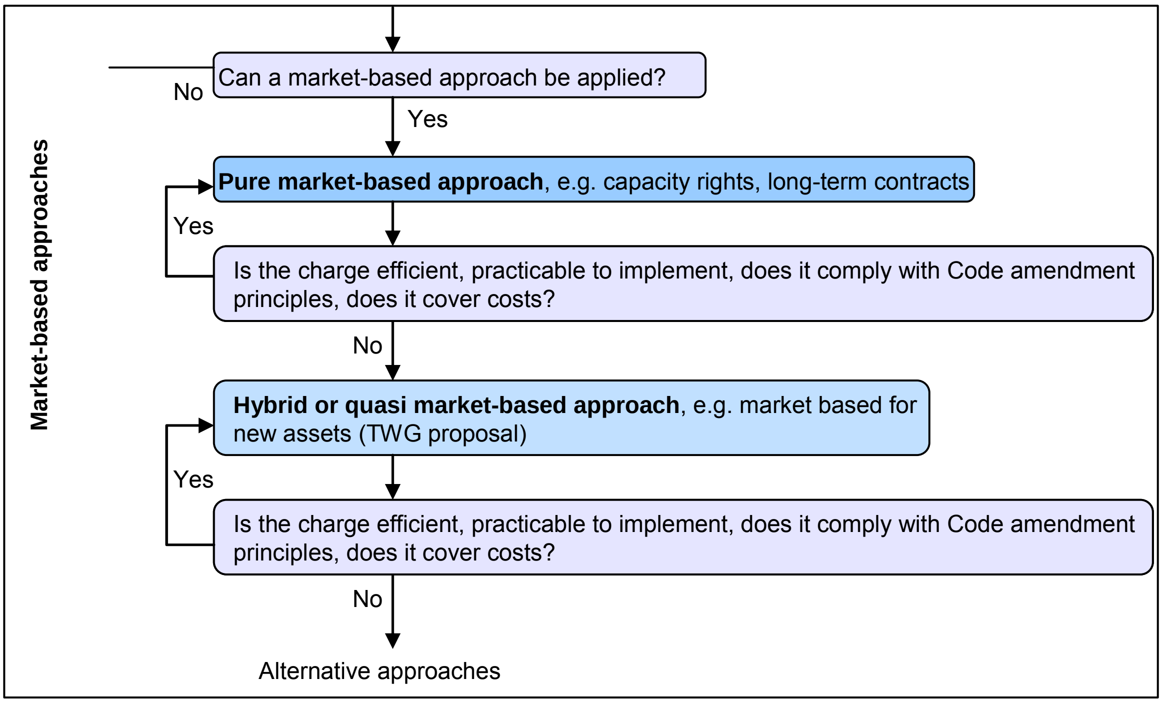
4.2.4 When the stakes are high, as they are with some aspects of the current TPM, the incentives on parties to lobby the regulator are also high. The potential greater durability and stability of market-based charges is an attractive feature, especially for charges that can influence significant long-term investment decisions in the grid, generation, demand management and other sectors of the economy.

4.2.5 As has already been noted, the statutory objective of the Authority requires it to promote efficient outcomes in the electricity industry for the long-term benefit of electricity consumers. The Authority also set out in its interpretation of its statutory objective that it believes the potential costs of regulatory uncertainty and ad-hoc interventions should be taken into account in determining minimum total costs (paragraph A46, Appendix A, *Interpretation of the Authority's statutory objective*). As a consequence, the Authority is also interested in promoting the durability and stability of the TPM as it believes this will promote competition, reliability and efficiency for the long-term benefit of electricity consumers.

4.2.6 For these reasons the Authority's preliminary view is that its first preference is to adopt market-based approaches to TPM charges, wherever it is confident such charges will be efficient and their implementation will be practicable and that any Code amendments needed comply with the Authority's Code amendment principles, including those elements relating to cost-benefit analysis. The main reasons why a market-based outcome may not be efficient is the presence of market power or externalities, or because its implementation may impose excessive transaction costs.

4.2.7 By a market-based approach to charges the Authority means either charges established by the interaction of buyers and sellers in a workably competitive market or charges which are likely to mimic or replicate such charges. The Authority's preliminary view is that it would prefer to adopt charges that are established by the interaction of buyers and sellers over charges which are thought likely to mimic or replicate such charges. This is because charges thought to mimic market-based charges may not do so in practice, and are unlikely to adjust as efficiently as those established directly by market activity.

Figure 5: Application of economic framework: market-based approaches

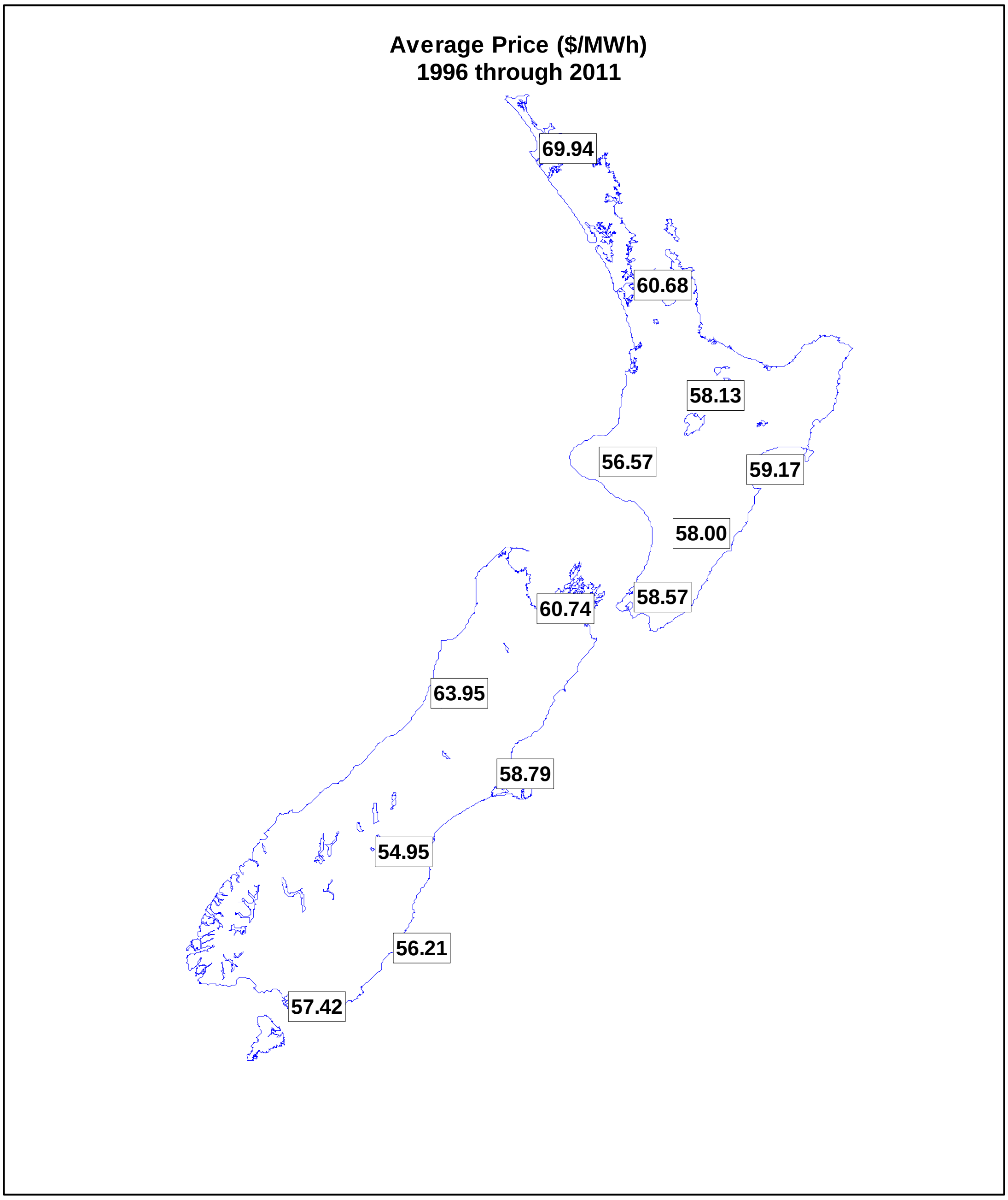


4.3 Pricing: Market-based approaches - practice

Market-based approaches based on locational marginal pricing

4.3.1 In New Zealand, wholesale electricity spot prices are locational marginal prices (LMPs); the price at each node reflects the marginal cost or value of increasing the supply of electricity by one unit at that node or location on the grid, given the grid configuration and capacity available at that time. This is illustrated in Figure 6.

Figure 6: Historical average nodal prices at various locations in New Zealand



4.3.2 The result is that the prices grid users pay and receive reflect the marginal cost of electricity at different points on the grid. In general, the further a consumer is from major sources of supply, the higher the price on the wholesale market of the electricity they consume. Similarly, generators typically receive higher wholesale market prices the closer their generation is to major load centres, such as Auckland. Producers and consumers inevitably take these differences into account when making investment, production and consumption decisions.

4.3.3 In the 1990s, when wholesale electricity markets were first being developed around the world, it was thought by many that LMP, or nodal pricing as it is more commonly called in New Zealand, was the key to market-driven pricing and investment decision-making for transmission. The thinking was that grid users would have incentives to enter into investment contracts with grid owners or investors to expand parts of the grid in order to reduce the differences in nodal prices by reducing the transmission losses and constraints that would otherwise occur. It was thought these investments could be funded either by:

(a) giving the investors rights to the loss and constraint rentals arising across the assets they funded – that is, financial transmission rights (FTRs); and/or

(b) by buying and selling the electricity transported across the assets investors had funded and retaining the profits from this, as has been suggested recently for the HVDC.

4.3.4 The incentives provided by nodal price differentials and the sums reduced transmission loss and constraint rentals could generate have, in practice, proved to be significantly less than what would be required to have grid expansion funded by ‘merchant’ transmission investors.

4.3.5 Three factors, each of which suppresses nodal prices differentials and loss and constraint rentals, explain this revenue shortfall:

(a) economies of scale in grid investment lead to building ahead of actual demand so the capacity of much of the grid is significantly greater than necessary to satisfy current demand;

(b) the administrative planning and approval processes for grid investments results in the construction of grid expansions in advance of when they are economically needed. This is because the incentives on investment and regulatory decision-makers result in them being biased in favour of promoting and approving early construction; and

(c) in the absence of market-derived scarcity pricing, the wholesale market price at a node does not rise to the value of un-served energy at times of insufficient supply at the node. This is because demand (and, as a result, price) is administratively suppressed by the System Operator so it equates to available supply.

Long-term contracting

4.3.6 Although development of a market-based approach to grid charges based on nodal price differentials has not proved practicable for funding all grid assets, a market-based approach based on long-term contracting has been adopted in New Zealand for charging for connection assets.

4.3.7 When Transpower provides connection assets under a long-term input connection contract, the charges are negotiated between Transpower and the customer prior to the investment being undertaken. The difficulties presented by Transpower's potential market power in such negotiations are circumvented by customers being free to enter into the contract or default to paying the standard connection charges according to the TPM.

4.3.8 When connection assets are provided by Transpower under a new investment contract the replacement cost used in determining the connection charge is determined in accordance with the contract and not the TPM.

4.3.9 For connection assets not subject to long-term input connection or new investment contracts the current TPM reflects fairly closely the kinds of charging regime that it is likely the parties would have negotiated, had they done so in a workably competitive market prior to the investment being undertaken.

4.3.10 Although this results in consumers paying for the assets that connect them to the grid, this is not inconsistent with the analysis above that suggests that in workably competitive markets most of the costs of transport services, **above those incurred by the 'best' located supplier**, are borne by producers, not consumers. An electricity consumer connects to the grid to access generators beyond its own location and so, by definition, the 'best' located supplier or generator of power it is accessing is beyond its connection assets. Consumers generally bear the costs of accessing power from the 'best' located generator beyond their connection assets.

4.3.11 Apart from some disagreements about the depth of the definition of connection assets, the connection charge under the current TPM has generated little controversy. This is not surprising in view of the comments above about the incentives to lobby against market-based approaches compared with administered charges.

4.3.12 Given this advantage of market-based approaches in terms of efficiency, regulatory durability and stability it should not be a surprise that there have been other attempts to promote transmission pricing solutions based on this approach.

4.3.13 In the period 2001-2, the Transport Working Group (TWG) of the Electricity Governance Establishment Committee (EGEC) developed Part F of EGEC's proposed Rules. This included a market-based decision-making framework for investment in the grid and transmission alternatives.

4.3.14 A corollary of the approach was that payments for all upgraded grid assets – connection, interconnection and HVDC assets – would have been on a long-term contractual basis. Over time, as more and more grid assets were up-graded, long-term contracts would have replaced the TPM as the means by which Transpower's revenue was generated.

4.3.15 When the Electricity Commission was established in 2003 a different version of Part F of the Electricity Governance Rules was developed by the Ministry of Economic Development (MED). This was based on an administrative approach to deciding on transmission investments, and resulted in administratively set charges for non-connection assets being a feature of the TPM.

4.3.16 Why the administrative approach was preferred is unclear. One possible reason is concern that the market-based approach in the TWG proposal would have resulted in under-investment due to problems with free-riders; but the TWG proposal included decision-making procedures that were designed to overcome free-rider problems. Another possible reason is a view that the TWG decision-making process would be too time consuming and costly. However, this must be considered against the time spent and costs incurred since 2003 debating transmission investment and the TPM.

4.3.17 As a result of the 2009 Ministerial Review into the Performance of the Electricity Market the role of approving grid investments passed from the Electricity Commission to the Commerce Commission and not to the Authority. Moreover, most of the grid upgrade expenditure likely to be required in the next few years has already been approved by the Electricity Commission. As a result, adopting the approach of TWG would not have much impact on transmission charges for a significant period of time.

Capacity rights

4.3.18 During consultation by the Commission on the TPM in 2009-10, the NZIER proposed two alternative market-based approaches to charging for the HVDC link. These involved:

(a) *capacity rights:* This would involve the owner of the HVDC auctioning time- and day-specific capacity rights to use the link, and these rights could be traded through a secondary market. Generators would need to hold capacity rights in order to be dispatched if the ensuing power flows resulted in energy being injected into the HVDC link. Holders of capacity rights would also have rights to receive HVDC loss and constraint rentals; and

(b) an *'arbitrageur'* approach, where the owner of the link could trade its capacity by purchasing power in one island and selling it in the other.

4.3.19 These did not find favour with the Commission[17] but a version of capacity rights was considered at some length by TPAG. TPAG reported:[18]

> In relation to capacity rights, a range of views exists. Capacity rights would appear more costly to implement than other options, but its benefits may be

[17] Electricity Commission, *Transmission Pricing Review: Stage 2 Options*, July 2010.

[18] TPAG Report p.2.

significant, particularly if it reveals willingness to pay. However, if a capacity rights option were to be considered further, a range of substantial issues would need to be considered including: how it might be implemented; whether there would be benefits in its introduction at this time (rather than at the time of a major new investment in the HVDC link), and how it would fit with other market design elements such as financial transmission rights.

Q3. **Do you agree that a market-based TPM would tend to promote efficiency in grid use and in investment in the grid, generation, demand management and the electricity industry more generally? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?**

Q4. **Do you agree that a market-based TPM is likely to be more durable and stable than approaches involving administered charges? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?**

Q5. **Do you agree the Authority's first preference should be to adopt market-based approaches to TPM charges wherever it is confident such charges will be efficient, implementation will be practicable, and that any Code changes needed comply with the Authority's Code amendment principles? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?**

Q6. **In light of TPAG's views, do you consider there would be any merit in the Authority devoting further effort to developing market-based TPM charges for interconnection and/or HVDC link assets? If so, what are your reasons and how do you think this would be best progressed? If not, what are your reasons?**

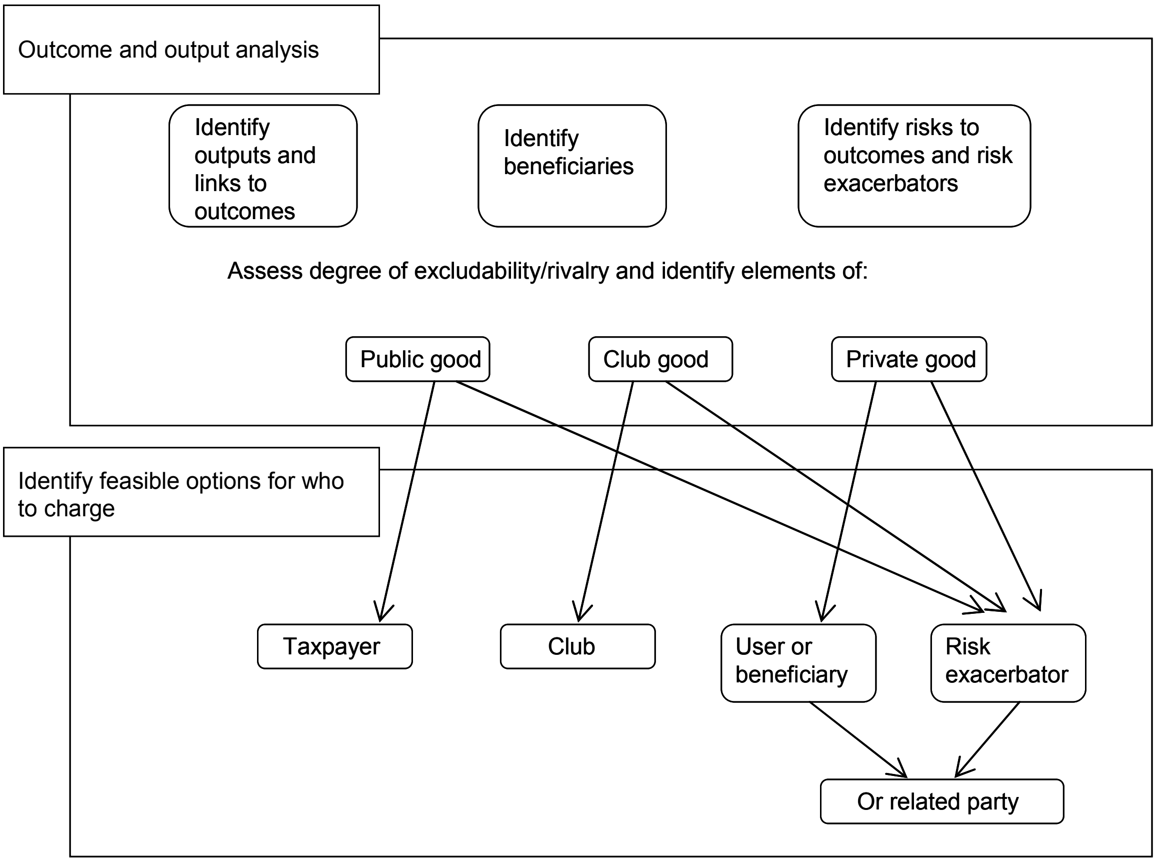
4.4 Pricing: Administrative approaches

4.4.1 The problem of determining by administrative means who to charge for a good or service and what the charge should be is, of course, not unique to transmission. It is a common problem encountered in public policy. The Authority considers that the Treasury's *Guidelines for setting charges in the public sector*[19] provides a useful basis for identifying which parties should be charged for a good or service and what charges they should face. This is an approach applied across government in New Zealand and has become a standard approach for determining by administrative means which party should be charged for a good or service and what charge they should face.

[19] The Treasury, *Guidelines for setting charges in the public sector,* December 2002.

4.4.2 Figure 7, which is reproduced from the *Guidelines*, provides a summary of the overall approach as set out in the Treasury's *Guidelines*:

Figure 7: Identification of which party to charge[20]



4.4.3 The Authority considers that its statutory objective should define the outcomes it seeks. In the current context, the Authority believes this translates into seeking a TPM which promotes the efficiency of the electricity industry for the long-term benefit of electricity consumers.[21] This will be achieved if the TPM promotes efficient use of the existing transmission grid and efficient investment decision-making in relation to the grid, demand-side management, generation and elsewhere in the electricity industry.

4.4.4 The distinction between public goods (or services), club goods and private goods depends on the degree to which parties can be excluded from consuming the good ('excludability') and the degree to which consumption of the good by one

[20] The Treasury, *Guidelines for setting charges in the public sector,* December 2002, figure 1, page 13.

[21] See Figure 4 for an explanation of how the Authority considers that all three limbs of its statutory objective ultimately relate to efficiency.

party precludes its consumption by another ('rivalry' in consumption). Table 2 below defines the various categories and gives examples.

Table 2: Determination of type of good

	Excludable	Non-excludable
Rivalrous	Private goods Food, clothing, cars, fishing regulated by quotas	Commons Unregulated hunting and fishing of scarce resources
Non-rivalrous	Club goods Public swimming pools, satellite TV, libraries	Public goods Free-to-air TV, defence, police services

4.4.5 In practice, the distinctions between the different categories are not hard and sharp. For example, if it is a very hot day and many people turn up to a modest-sized public swimming pool at the same time, its consumption will quickly become 'rivalrous', and it would be more accurately described as a private good than a club good. Free-to-air TV (and radio) can be made a club good, rather than a public good, by requiring those with TV sets to hold licenses in order to view free-to-air television and policing this requirement. This was the practice in New Zealand for many years.

4.4.6 Commons can be transformed into private goods by defining property rights in them. This is what New Zealand did when it developed the Individual Transferable Quota (ITQ) management system for fisheries. The same process occurred in the past in relation to most frequencies of the radio spectrum; some frequencies, such as those you use to lock your car door, monitor sleeping babies, and run Wi-Fi have been recently returned to commons from now redundant uses.

4.4.7 It is not generally possible to tell what parts of an interconnected grid the electricity generated or consumed by a particular party moved along during its journey from producer to consumer. Nor is it generally possible to tell which party generated the electricity consumed by some other party. However, it is possible to prevent a consumer or generator from using the transmission network (i.e. the grid is 'excludable').

4.4.8 A grid might be thought to be like a public swimming pool with the extent to which the use of a grid is 'rivalrous' depending on the level of demand relative to capacity. As the use of grid assets increases, the level of transmission losses increases more than proportionately. Additional use affects all existing users. For this reason, it is appropriate to consider a grid is ‘rivalrous’ in consumption and, since it is also excludable, to conclude a grid is a private good.

4.4.9 Figure 6 indicates that according to Treasury’s *Guidelines* the potential parties to charge for a grid are exacerbators, users or beneficiaries, or a party or parties related to one or more of these groups.

4.4.10 The preliminary view of the Authority is that if it is required to consider an administrative approach to setting transmission charges:

(a) ,the Authority’s first preference should be to charge exacerbators and its second preference should be to charge beneficiaries;

(b) users should only be targeted as a proxy for beneficiaries. The Authority notes that when use is voluntary it is reasonable to assume users are beneficiaries, although their benefit may not exceed the costs of provision if they are not being charged; and

(c) a related party should only be targeted when it is clear that it will pass the economic impact of the charge on to exacerbators or beneficiaries, as the case may require.

4.4.11 Making exacerbators face the costs of their decisions would eliminate provision of the good or service when the cost exceeds the benefit to exacerbators, and so improve the performance of the economy as a whole by reducing wasteful activities. Charging beneficiaries, however, only ensures that those that would be willing to pay are required to do so. If use is not voluntary, the user may not be a beneficiary.

4.4.12 Adopting the exacerbators pay approach ensures that, to the extent it is practicable, those making decisions relating to the grid face the full social costs of their decisions, and not just their private costs. This enhances efficiency by avoiding expenditure on socially inefficient activities. Exacerbators pay is the principle underlying the event charges for under-frequency events under clause 8.64 of the Code.

4.4.13 Parties can of course take decisions that avoid the need to augment the grid, such as building generation in an area that would otherwise require expansion of grid capacity. In effect, parties taking such actions are ‘negative’ exacerbators. This is why alternatives to transmission are considered in transmission investment decisions.

4.4.14 It could be argued that the transmission provider and/or parties paying for the grid should pay ‘negative exacerbators’ to undertake investments that avoid the need for augmentation of the grid. However, it is important to consider the private benefit of such transmission alternatives, as it is often the case that the private benefits exceed the costs so the investments would proceed anyway. If this is the case, a payment from the transmission provider and/or parties paying for the grid in such situations would be inefficient. This is likely to be significant in a market like New Zealand where the benefits can be large because of nodal pricing.

4.4.15 There are, nevertheless, examples where negative exacerbators are paid for actions that avoid the need to augment the grid, such as offering interruptible load.

4.4.16 If it is not possible to identify exacerbators, or the revenue that can be derived from charging them the costs their decisions impose does not cover full costs, the next series of questions should be:

(a) Can the parties deriving benefits from the provision of the good (or service) be accurately and appropriately identified?

(b) If they can, would it be efficient to charge them or one or more subsets of them, and to what extent?

(c) How should any charges on beneficiaries be levied so as to promote efficiency?

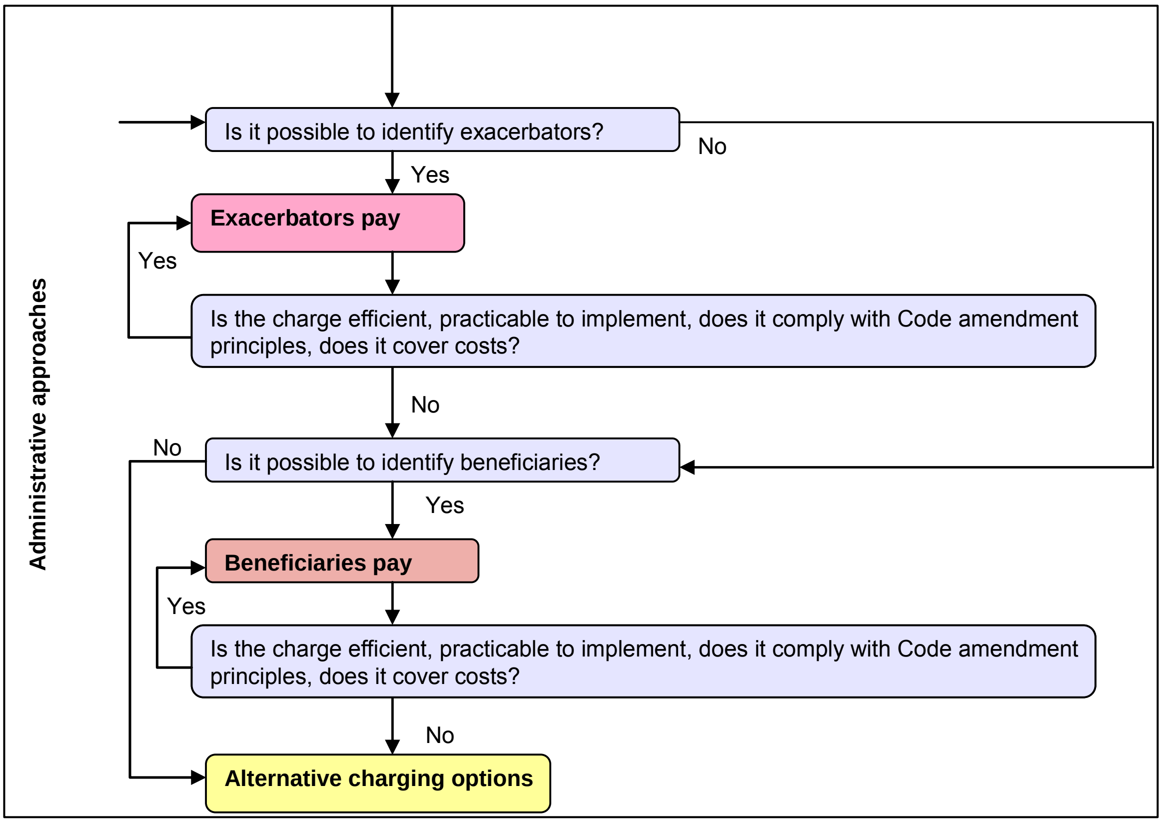
4.4.17 It may not be possible to clearly identify either exacerbators or beneficiaries in relation to an activity. Even if it is, to ensure that the pricing approach is efficient, it is important to consider whether there are adverse efficiency consequences such that the costs of making exacerbators or beneficiaries alone pay exceed the benefits.

4.4.18 If exacerbators or beneficiaries cannot be identified, or it would be inefficient to make them pay or to pay enough to fully cover costs, an alternative charging option may have to be adopted.

4.4.19 In practice, this often involves spreading charges evenly across a broad base. A broad base lowers the charge per unit of the base, reduces the risks of creating inefficiency, is simple to administer, and makes it more difficult for parties to lobby against since their treatment is the same as everyone else’s.

4.4.20 The Authority’s preliminary view is that the Authority’s order of preference among administrated approaches to setting grid charges will be exacerbators pay, beneficiaries pay and, finally, alternative charging options. The Authority proposes to adopt the more preferred approach wherever and to the extent it is confident such charges will be efficient, implementation will be practicable, and that any Code amendments needed comply with the Authority’s Code amendment principles. If a preferred approach is unable to generate sufficient or any revenue while meeting these requirements, the Authority would consider the next ranked approach for either the whole or part of the revenue requirement.

Figure 8: Application of economic framework: administrative approaches



Q7.	**Do you agree the Authority's second, third and fourth ranked preferences should be to adopt the administrative approaches to TPM charges of exacerbators pay, beneficiaries pay and other charging options wherever it is confident such charges will be efficient, implementation will be practicable, and that any Code amendments needed comply with the Authority's Code amendment principles? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?**

4.5 Exacerbators pay

What is an exacerbator?

4.5.1 Section 3.4 defined an exacerbator as a party whose behaviour influences the requirement for an activity. More precisely, an exacerbator is a party whose action or inaction led to the need to undertake an activity.

4.5.2 A real-life example of an exacerbator comes from the experience of Southland District Council, which was faced with evidence of an unprecedented rise in rural road maintenance costs.[22] An investigation identified that, while increases in private light motor vehicle traffic had negligible impact upon regular road maintenance, the increase in heavy commercial traffic from milk tankers and logging trucks created a significant increase in road damage requiring increased road maintenance. The increase in traffic from milk tankers and logging trucks had resulted from dairying and forestry development.

4.5.3 In this case, the parties whose actions (or inactions) had led to the need for increased road maintenance – the exacerbators – were the parties that had undertaken the dairy and forestry development. This was because if they had not undertaken the development the need for increased road maintenance would not have arisen.

4.5.4 An important point to note from this example is that all users of the roads benefited from the increased road maintenance. However, only one group of parties took actions that led to the need to increase the road maintenance. If they had faced the full cost of their actions when they undertook their investment decisions some of the parties may not have proceeded with the investment and the need for increased maintenance would have been reduced.

4.5.5 Similar examples exist in transmission. An equivalent to this roading example would be where a major load decided to located in an area already serviced by the transmission network, leading to the need to expand the capacity of the interconnected network. If faced with the full cost of the necessary expansion, the load may choose to invest in generation or load management to avoid the need for expansion or to locate elsewhere.

4.5.6 An equivalent generation example would be where a generator undertook a development in an area connected to the grid but the development leads to network congestion and a need to expand the capacity of the interconnected network. If faced with the full costs of the expansion, the generator may either choose to locate elsewhere or undertake the development in a manner that minimised the need for the expansion.

4.5.7 As with the roading example, in both these load and generation examples, if the transmission investment went ahead other parties would have benefited from the resulting decrease in congestion (or deferment of congestion). However, only one party undertook actions (or failed to take actions) that led to the need for the investment, and may have acted differently if they were required to pay for the full costs resulting from their actions.

4.5.8 The concept of exacerbators pay could apply to any example where a party's actions or inactions led to a need to augment the grid. The most obvious

[22] Example from Mitchell, LN and Seymour, D, *Getting a better bang for the pothole buck*, FCCP Policy Series No. 59, Frontier Centre for Public Policy, July 2009.

example is a generator or a load that was considering whether to locate in an area not connected to the transmission grid. Their decision on whether to proceed or not would determine whether the augmentation was necessary.

How do you identify exacerbators?

4.5.9 Applying an exacerbators pay approach requires a methodology for identifying exacerbators that can be applied reasonably consistently over time and across the grid. This is to ensure that all parties face equivalent incentives to act efficiently so that the efficiency benefits of applying an exacerbators pay approach are obtained throughout the grid.

4.5.10 The method for identifying exacerbators also needs to be cost effective to ensure that the costs of identifying exacerbators do not compromise efficiency benefits.

4.5.11 It is also preferable to identify exacerbators prior to augmenting the grid. This gives parties that would pay the charge the opportunity to incorporate the cost implications of their actions or inactions into their own decisions, giving them incentives to act efficiently. However, an ex-post application of the approach may still improve efficiency by sending a clear signal to others that they should consider the indirect costs to society of their decisions, if these differ from their private direct costs, as they will be required to bear these costs.

4.5.12 To identify exacerbators, the first step is to identify any actions or inactions by parties using the grid or who wish to use the grid that lead to the need to augment the grid. The actions or inactions can be discerned from other options the parties may have had by the fact that, if they chose another option, the need for augmentation of the grid would have been avoided.

4.5.13 Actions or inactions that may lead to the need to augment the grid could include:

(a) a decision to locate generation or major load in a location that requires connection to the grid, augmentation of an existing connection, or augmentation of interconnection assets;

(b) a significant increase in peak injection or off-take of power or, conversely, a decision to not invest in, for example, off-take management; and

(c) drawing reactive power and/or not investing in static reactive compensation equipment.

4.5.14 This list is not intended to be exhaustive. There may be other actions or inactions that may require augmentation of the grid. Under an exacerbators pay approach, whenever any material augmentation of the grid is being considered an assessment of exacerbating actions or inactions would be made to determine which parties, if any, should contribute to paying for it.

Q8.	**Do you agree these actions can exacerbate investment? Are there other actions and, if so, what are they?**

4.5.15 The next step is to identify the parties whose actions or inactions are leading to the need to invest in the network. As the Southland District Council roading example illustrates, the identity of exacerbators may not be immediately obvious and may require empirical or other analysis to confirm their identity.

4.5.16 Parties who may take actions or fail to take actions that result or resulted in the need to invest in the transmission grid may be:

(a) new load or generation, e.g. a new consumer or a generator entering a region either not served by the transmission network, or where the existing network has insufficient capacity to cater for the additional off-take or injection; or

(b) existing load or generation, e.g. a customer not investing in load management or SRC equipment, or increasing the capacity of their generation or investing in new equipment resulting in increased load.

4.5.17 The key issue with identifying exacerbators is determining which party or parties have the ability to act differently, thereby avoiding the need to augment the network. With new load or generation this should normally be straightforward as in the absence of a decision to undertake the load or generation investment augmentation of the network would be unnecessary. With existing load or generation, however, there may be multiple parties, only some of whom are taking actions or inactions leading to a need to augment the network. For the exacerbators pay approach to endure it is important that a robust methodology is applied to differentiate exacerbators from other parties.

Q9.	**Do you agree that exacerbators should be identified by determining which party or parties have the ability to act differently, thereby avoiding the need to augment the network? Is there an alternative approach? If so, please provide details.**

What price should exacerbators face?

4.5.18 Under exacerbators pay the party or parties whose actions or inactions led to the cost in question is responsible for mitigating that cost. This provides incentives on the parties responsible to consider what alternative actions they could take to avoid the need for the expense.

4.5.19 To ensure exacerbators have incentives to make efficient decisions, in theory the price they should face should be based on the long run marginal cost (LRMC) for the grid of their actions or inactions. This provides them with incentives to consider alternatives, such as connecting elsewhere, managing their load, investing in their own generation (if they are a load) or undertaking the investment themselves. By charging LRMC, exacerbators can compare this against the cost of alternatives and incorporate this into their decision on whether to proceed with the exacerbating action or inaction.

4.5.20 However, as noted by NERA (2009),[23] the implementation of pricing based on LRMC is not straightforward in practice. In particular, as NERA notes efficient augmentation of the transmission network may be "lumpy", in which case the LRMC is likely to fluctuate over time. Depending on the time horizon used to calculate LRMC, a price based on LRMC may therefore also fluctuate, compromising the provision of a price signal that is durable over the long term. NERA therefore suggests a price based on an estimate of LRMC over a relatively long time horizon, such as 20-30 years.

4.5.21 An alternative to LRMC is long-run incremental cost (LRIC). In the context of exacerbators pay, LRIC is the additional cost of augmenting the network, over and above that already planned, because of an exacerbator's actions or inactions. As noted by National Grid (2008), the rationale for applying a price based on LRIC is as follows:[24]

> "…efficient economic signals are provided to users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that users of the transmission system at different locations would have on the transmission owner's costs, if they were to increase or decrease their use of the respective systems."

4.5.22 A key consideration with any pricing method is how to allocate costs among multiple users. With a price based on LRMC a cost allocation method is not necessary since the price is based on the impact on the margin (e.g. per MW) of exacerbators' actions or inactions. As a result, irrespective of the number of users, the price that they face will be efficient.

4.5.23 However, a cost allocation method is necessary for LRIC-based prices where there are multiple exacerbators. The usual method is to allocate the incremental cost by load or injection. This ensures that each customer faces the incremental cost resulting from their use of the network, providing incentives for them to act efficiently.

4.5.24 Several of the pricing methodologies that have been considered in the review of the TPM could be used to apply an exacerbators pay approach. These

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[23] NERA Economic Consulting, *New Zealand transmission pricing project: A report for the New Zealand Electricity Industry Steering Group*, 28 August 2009.

[24] National Grid, *Statement of the use of system charging methodology*, 1 April 2008.

approaches can be divided into LRMC-based and LRIC-based methodologies, as shown in Table 3.

Table 3: Options for pricing methodologies under exacerbators pay

Method	LRMC or LRIC	Explanation
Long-term contract	LRIC	Contract price based on cost of increment
Locational signalling, e.g. tilted postage stamp	LRMC	Postage stamp charges varying by region based on estimate of LRMC of expanding grid capacity
Peak injection or off-take charge	LRMC	Charge based on estimate of LRMC
kvar charge	LRMC	TPAG recommendation for SRC was a charge set at the LRMC of grid-connected SRC investments
Deep connection or “but-for”	LRIC	Charge based on cost of increment

4.5.25 Some of these charging methods are targeted at specific exacerbating activity, such as the kvar charge, which targets parties drawing reactive power, and locational signalling, which targets the location decisions of exacerbators.

4.5.26 Other charging methods could be applied to multiple forms of exacerbating activity, such as long-term contracts or “but-for”. These are LRIC-based charging methods so that the charge is determined by the cost of the increment, which means these methods of charging need not be issue-specific.

4.5.27 Some combination of these options may also be appropriate, e.g. a kvar charge combined with deep connection.

4.5.28 The Authority considers that exacerbators pay approaches should be assessed according to the extent to which they promote the statutory objective with respect to elements of transmission pricing for which a satisfactory market-based approach has not been found. That is, the options should be assessed according to the extent to which they promote efficient use of the transmission network and efficient investment in the grid, generation, demand management and industry as a whole. Further, any proposal to amend the TPM in order to implement exacerbators pay would need to comply with the Authority's Code amendment principles, which includes requirements relating to cost-benefit analysis.

Q10.	**Do you agree with the assessment of the price that should apply to exacerbators? Do you agree with the assessment of how exacerbators pay should apply in practice? Do you agree with the proposed approach for identifying the preferred option or options for applying exacerbators pay? Please provide explanations in support of your answers.**

What if exacerbators pay is not viable to fully recover costs?

4.5.29 It may not always be possible to identify exacerbators. Even if it is, it may be inefficient to apply an exacerbators pay approach because, for example, the costs (and, in particular, the transactions costs) of making exacerbators pay may exceed the benefits, or the revenue from charging exacerbators may be less than the full costs.

4.5.30 This may occur, for example, when there is an influx of multiple small users or a change to electricity use by multiple small users that requires augmentation of the network. In this case, exacerbators may be so numerous that the transaction costs involved in identifying exacerbators versus other users are likely to exceed the benefits. It may, however, be possible to get around this problem by applying the charge to an intermediate party, e.g. if the exacerbators are small consumers, the charge could be applied to distributors or retailers. If charging intermediate parties was considered, it would be important to ensure that the charge would be passed on in a manner that provided a price signal so that exacerbators faced the cost of their exacerbating activity.

4.5.31 Alternatively, it may be difficult to determine the extent to which the actions or inactions of different parties contribute to the need for the investment in the grid, making determination of an appropriate charge difficult. Where it is difficult to identify exacerbators or the costs of making exacerbators pay exceed the benefits, alternative pricing approaches need to be considered. In the first instance, this should be beneficiaries pay but, if this approach is also not fully viable, some other pricing approach may be necessary.

4.5.32 Where exacerbators have been identified and it appears efficient to charge them, it is important to confirm that this would not result in them acting inefficiently in order to avoid the charge. Inefficient actions could include lobbying to ensure certain activities were not considered exacerbating, reconfiguration of their own assets, or any other activity that would enable the exacerbating activity to continue while avoiding the charge. To avoid this problem, it may be necessary to include a mechanism to avoid promotion of inefficient behaviour, such as the PDP (clauses 36-42 of Schedule 12.4 of the Code).

Q11. Do you agree these considerations should be taken into account under an exacerbators pay approach? Please provide an explanation in support of your view.

4.6 Beneficiaries pay

What is a beneficiary?

4.6.1 A beneficiary can be defined as a party for whom the private benefits of the investment proceeding exceed the costs, and would therefore be willing to pay for it if that were the only means by which the benefit could be acquired. As TPAG noted,[25] there are two benefits of a beneficiaries pay approach, if it can be applied effectively:

(a) investment efficiency benefits through improved investment decision making; and

(b) benefits in terms of improved durability of the allocation methodology.

4.6.2 Taking the example of the Oamaru farmer selling potatoes in Auckland referred to in Section 4.1, the farmer would be willing to contribute to the cost of the roads and inter-island shipping necessary to get the potatoes from Oamaru to Auckland, provided the value they obtain from selling potatoes in Auckland exceeds the costs of getting them there. Similarly, Auckland consumers would be willing to contribute to the costs of getting the potatoes from Oamaru to Auckland provided the value they obtain from the Oamaru potatoes exceeds the costs, including the costs of alternatives, such as potatoes grown in Pukekohe.

4.6.3 The important point to note is that a beneficiary will only be willing to pay up to the private value they obtain from the service. As TPAG noted, if a beneficiary is made to pay more than their private value they will have incentives to ensure that the investment does not proceed. Similarly, beneficiaries who are under-allocated costs may have incentives to lobby for the investment, which if it proceeded would impose costs on others, including their potential competitors. However, provided allocation of costs is undertaken on an accurate basis and the value to beneficiaries exceeds the costs, making beneficiaries pay promotes efficiency. This is because beneficiaries will have incentives to consider the costs of the investment in their own decisions and will also have incentives to seek to minimise the costs of the investment itself.

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[25] Transmission Pricing Advisory Group, *Transmission Pricing Analysis: Report to the Electricity Authority*, 31 August 2011, paragraph 4.5.2, page 34.

4.6.4 As with exacerbators pay, the concept of beneficiaries pay could apply to any aspect of the grid where parties could be identified who would be rationally willing to pay for it. With some assets though there may be large numbers of beneficiaries. It is therefore important to ensure that identification of beneficiaries is only undertaken up to the point where the benefits of identifying the beneficiaries and making them pay exceed the costs.

How do you identify beneficiaries?

4.6.5 Applying a beneficiaries pay approach requires a reasonably robust method for identifying beneficiaries that can be applied consistently over time and across the grid. The benefits of improved investment efficiency and durability will be compromised if beneficiaries cannot be cost-effectively and clearly identified. In an interconnected electricity network there can be practical issues that make identifying beneficiaries costly and open to dispute.

4.6.6 TPAG debated at length the various means for identifying beneficiaries of the HVDC link but did not reach a consensus on whether the beneficiaries could be usefully identified for charging purposes.

4.6.7 One approach TPAG did not explicitly consider is to treat the HVDC link as a quota restriction on trade (in electricity) between the North and South Islands.

4.6.8 If there was no HVDC link this would equate to a quota of 0 MW of electricity, or a complete ban on trade between the economies of the two islands. If there is a link, its capacity is the quota restriction. Determining which parties benefit from the removal or relaxation of trade restrictions, such as quotas, and measuring the extent to which they benefit, and over what timeframe, is a common problem addressed by trade economists when advising governments on trade negotiations.

4.6.9 Trade economists have a range of economic models, including computable general equilibrium (CGE) models, for undertaking this task. The Authority considers it would be desirable to apply these models to the identification of the groups which benefit from components of the grid and to measure the extent to which they benefit.

4.6.10 As TPAG noted, the greatest value from applying a beneficiaries pay approach can be obtained by linking it to investment decision-making. It is, therefore, preferable that beneficiaries are identified prior to decisions being made, and have decision rights in the investment approval process.

4.6.11 For this reason it is preferable for a beneficiaries pay approach to be applied before a new investment is approved, as prospective beneficiaries have an incentive to reveal their interests if they wish the investment to proceed. It also provides the opportunity for their willingness to pay to be incorporated into decision making. However, allocation of costs is still based on uncertain information as to the actual value to the potential beneficiaries, increasing the risk of inaccurate allocation of costs amongst those paying for the investment.

4.6.12 There can still, however, be considerable value in applying a beneficiaries pay approach after an investment has been made as this will impact on future investment decisions. Allocation of sunk costs can drive expectations about how sunk costs from future investments will be allocated, and parties will incorporate this into their decision making. Moreover, allocation of costs after they have been sunk provides more certain information on the benefits of the investment to particular parties, and therefore how the costs should be allocated.

4.6.13 In order to identify beneficiaries, it is necessary to determine the benefits participants are obtaining from the network. Benefits to participants can include:

(a) reliability;

(b) security;

(c) increased competition; and

(d) more profitable power sales through increased generation volumes and/or higher generation prices.

4.6.14 Table 4 below shows three main options:

Table 4: Identification of beneficiaries

	Approach to identifying beneficiaries	Analysis required/undertaken
Users as a proxy	This would use a non-price metric, such as shares of assets based on flows.	Flow-tracing work from stage 2 of the Review Earlier flow-based TPM
'What if' analyses	Comparisons of volume/price benefits to participants with and without investments. **Different options:** • For new or existing assets. • Based simply on with or without the asset, or making assumptions of alternative generation expansions.	Analysis of 'No HVDC' counterfactual using GEM model Treat the HVDC link as a quota restriction on trade (in electricity) between the North and South Islands, and apply trade CGE models
Ex-ante identification	Identify beneficiaries as part of the grid investment approvals process. • Need to identify consumption and	• Qualitative discussions by TPAG on the beneficiaries of the HVDC

	Approach to identifying beneficiaries	Analysis required/undertaken
	generation types • Estimate benefits to consumption and generation types • Set assumptions around future projections (demand generation) • Agree how to handle future beneficiaries	• Qualitative discussions by NERA in Electricity Industry Transmission Pricing Project • mini-grid investment test at time of HVDC upgrade

Q12.	**Do you agree that these ways can be used to identify beneficiaries? Are there others? If so, please provide details.**

What pricing should apply to beneficiaries?

4.6.15 Ideally, the price that should apply to beneficiaries should reflect the lesser of the charge which will fully recover the costs of the grid being paid by beneficiaries and the anticipated (*ex ante*) value to them from the services provided by the grid. This will avoid the problems noted earlier of under-allocation of costs (which provides an incentive for lobbying and shifting the costs onto others) and over-allocation of costs (which provides incentives to lobby against efficient investments).

4.6.16 It is preferable that the cost allocation to beneficiaries is fixed at a point in time, as this avoids the problem of the method of cost allocation influencing their use of the asset. Such an "incentive free" approach will ensure that the party only uses the asset when the benefits they obtain exceed the costs, rather than their usage being determined by how much they are charged. It is therefore preferable to avoid cost allocation approaches that are based on either usage or shares of usage.

4.6.17 Application of beneficiaries pay requires a method for determining what parties are willing to pay. Ideally, it is preferable that parties reveal their willingness to pay directly, rather than using a proxy method such as use of an asset.

4.6.18 Determining the extent to which a party or group benefits from the grid involves considering the costs of any alternatives available to it because the benefit cannot exceed the cost of its next best alternative.

4.6.19 To illustrate, a major customer directly connected to the grid with its own co-generation plant obtains a benefit from the connection in the form of the back-up it provides to its own generation capacity. The limit of its benefit from grid connection (assuming it does not sell any surplus electricity output) must be the costs of providing the back-up by the next best alternative, such as installing and operating a second-hand standby diesel generator.

4.6.20 Calculations set out in Appendix B, using the recent sale price of the Whirinaki reserve generation plant as a guide to the costs of large scale standby diesel generation in New Zealand, are instructive. These suggest that when the effects of Transpower's current upgrade programme are reflected in the overall level of charges, if the current HVDC link and interconnection charges were imposed on direct connected customers, some of them may decide to disconnect from the grid. This would be inefficient for New Zealand as a whole.

4.6.21 As regards the materiality of this possibility, the Authority notes that, in 2010, 37.7% of New Zealand's electricity consumption was by industrial users[26] and took place through only 2.0% of the country's Installation Control Points (ICP's).[27] Moreover, in 2010, 9.9% of the North Island's electricity generation occurred in co-generation plants.[28]

4.6.22 In view of these illustrative calculations, the Authority considers it would be desirable if the potential benefit of grid connection to major industrial users of electricity were more fully investigated than they have been to date.

Q13. Do you agree with the assessment of the price that should apply to beneficiaries? Do you agree with the assessment of how beneficiaries pay should apply in practice? Please provide an explanation in support of your answer.

Q14. Do you agree that prima facie the increase in transmission costs in the next few years may provide incentives for some direct connect customers to disconnect from the grid? Please provide any evidence and an explanation in support of your answer.

What if beneficiaries can't be efficiently identified or charging them is inefficient?

4.6.23 As with exacerbators, it may not always be possible to identify beneficiaries or, alternatively, charging beneficiaries may be inefficient or not yield adequate revenue to fully cover the costs of the grid. As with exacerbators, the beneficiaries may be so numerous that the transaction costs of making them rather than other groups pay may exceed the benefits.

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[26] MED, Energy Datafile, 2011, Table G.5a

[27] MED, Energy Datafile, 2011, Table G.5b.

[28] MED, Energy Datafile, 2011, Table G.2d.

4.6.24 Even if it is possible to identify the beneficiaries and the extent they benefit, it may not promote efficient outcomes to levy charges on all of them. For some, the benefit may be so small and the costs of setting, collecting and enforcing the charges may be so great that, taking transaction costs into account, it would not be rational to charge them.

4.6.25 In other instances, levying the charge may create inefficiencies that it is best to avoid. For instance, when Transpower first developed the TPM that is the basis of the current regime, it decided not to levy charges for the HVDC link on North Island consumers, even though it considered, rightly or wrongly, they were beneficiaries of the link. Its rationale was that the only effective way to charge North Island consumers was to impose a charge on each unit of electricity consumed in the North Island. If this was done, however, the sunk costs in the grid would affect the price and hence the current consumption of electricity, and Transpower considered this would be inefficient.

4.6.26 Another example is the view of some members of TPAG that the charges for the HVDC link should ultimately fall on consumers and not South Island generators. Their rationale was that imposing the charge on generators could lead to inefficiencies in investment decisions relating to generation and inefficiencies due to reduced competition for South Island generators (in particular, Meridian Energy) to expand plant in the South Island.

4.6.27 If exacerbators or beneficiaries cannot be identified, or it would be inefficient to make them pay, or to pay enough to fully cover costs, an alternative charging option will have to be adopted.

4.7 Alternative charging options

What options are there?

4.7.1 The aim of any method of charging for the grid is to minimise distortions in its use from the efficient level and incentivise appropriate investment. If the ideal is unachievable a regulator may have to be satisfied with a regime that:

(a) limits the distortion in use resulting from the imposition of charges; and

(b) ensures the costs of providing the grid are fully covered, so future investment in the grid is not inhibited by investors fearing they will not receive a return on their capital.

4.7.2 One approach that would do this would be to set the charges so full coverage of costs will occur, but levy the charges on an ‘incentive-free’ basis; that is, on a basis unrelated to the current level of usage of the grid.

4.7.3 This is the approach of one of the means of charging for the HVDC link considered by TPAG.[29] It suggested levying the charges for the link so as to fully cover its costs on the basis of the historical anytime maximum injections of South Island generation plants over some period in the past. Since current or future usage of the link would not influence the charges paid by generators, this charging regime would not influence the level of usage. TPAG also noted that compared with the status quo charging regime for the HVDC link, it would also:

(a) remove any competitive advantage for new generation development conferred on large incumbent generators, like Meridian Energy, in the South Island;

(b) remove the competitive disadvantage for new South Island generation relative to new North Island generation;

(c) remove incentives that discourage operating South Island power stations at full output; and

(d) keep transaction costs low.

4.7.4 TPAG concluded that "*it is feasible to design an HVDC cost allocation mechanism that is "incentive-free*" " but went on to express concern that such a regime may be unstable as it would incentivise incumbent South Island generators to lobby to have the charge removed on the grounds that it is unfair to charge existing generators and not new ones and is arbitrary.[30] Fairness is not, however, an element of the Authority's statutory objective.

4.7.5 Another approach is to set the charges so full coverage of costs will occur, but spread them out evenly across as broad a base as possible. The rationale is that spreading the charges broadly would tend to make them modest per unit of the base upon which they are levied. This should restrain the impact the charges have on usage and hence on the resulting inefficiency. Applying them evenly across the base is intended to reduce lobbying against the charges because each unit will be subject to the same charge.

4.7.6 The interconnection charge in the current TPM, which is applied at a uniform postage-stamp rate to all off-take customers on the basis of their usage relative to regional coincident peak demand (RCPD), is an example of this kind of charge. It has already been noted that the sharp increases in this (and the HVDC charge) in the near term to reflect Transpower's significant investments in the grid may be sufficient to incentivise some parties to disconnect from the grid in a manner inefficient for the New Zealand economy. Consideration may therefore need to be given to amending the PDP to address this issue.

[29] See TPAG Report, Appendix C.

[30] TPAG Report, p. 176.

Q15.	**Are there other alternative pricing options? Do you agree with the assessments of how incentive free and postage stamp pricing should be applied in practice? Please provide reasoning in support of your answer.**

5. Conclusion

5.1 Statutory objective and decision-making framework

5.1.1 The Authority takes the view that the framework for decision making about options for the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers.

5.1.2 This overall efficiency refers to both efficient use of the grid and efficient investment in the electricity industry – the grid, generation and demand side management – and by electricity consumers over time:

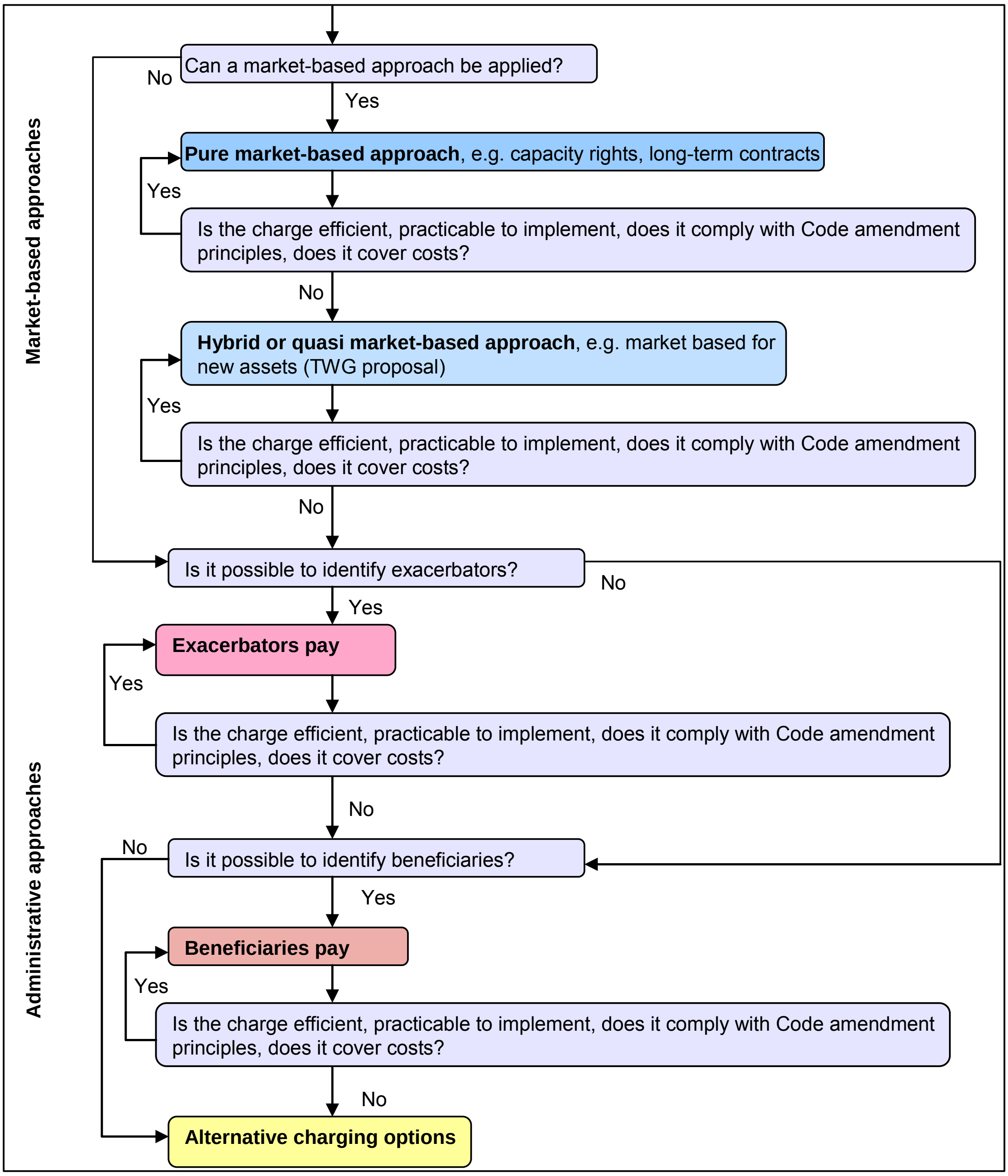
(a) efficient use of the grid focuses on least cost production and charging customers the efficient marginal costs of production; and

(b) efficient investment focuses on the lowest cost development of industry over time.

5.2 Decision-making and economic framework

5.2.1 The flowchart set out in Figure 9 outlines and summarises the Authority's preliminary view as to the decision-making process and economic framework it should consider.

Figure 9: Preliminary view of decision-making and economic framework for transmission pricing



Appendix A Format for submissions

Question No.	Question	Response
Q1	Do you agree with the Authority's interpretation of its statutory objective with respect to transmission pricing? If you agree, please explain why. If you do not agree, please explain how you consider the statutory objective should be interpreted with respect to transmission pricing and the reasons for your interpretation.	
Q2	Do you agree with the above application of the three limbs of the statutory objective to transmission pricing? If not, why not, and are there other examples of how transmission pricing can influence competition, reliability and efficiency?	
Q3	Do you agree that a market-based TPM would tend to promote efficiency in grid use and in investment in the grid, generation, demand management and the electricity industry? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	
Q4	Do you agree that a market-based TPM is likely to be more durable and stable than approaches involving administered charges? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	

Q5	Do you agree the Authority's first preference should be to adopt market-based approaches to TPM charges wherever it is confident such charges will be efficient and their implementation will be practicable and that any Code changes needed to do so comply with the Authority's Code amendment principles? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	
Q6	In light of TPAG's views, do you consider there would be any merit in the Authority devoting further effort to developing market-based TPM charges for interconnection and/or HVDC link assets? If so, what are your reasons and how do you think this would be best progressed? If not, what are your reasons?	
Q7	Do you agree the Authority's second, third and fourth ranked preferences should be to adopt the administrative approaches to TPM charges of exacerbators pay, beneficiaries pay and other charging options wherever it is confident such charges will be efficient, implementation will be practicable, and that any Code amendments needed comply with the Authority's Code amendment principles? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	
Q8	Do you agree these actions can exacerbate investment? Are there other actions and, if so, what are they?	
Q9	Do you agree that exacerbators should be identified by determining which party or parties have the ability to act differently, thereby avoiding the need to augment the network? Is there an alternative approach? If so, please provide details.	

Q10	Do you agree with the assessment of the price that should apply to exacerbators? Do you agree with the assessment of how exacerbators pay should apply in practice? Do you agree with the proposed approach for identifying the preferred option or options for applying exacerbators pay? Please provide explanations in support of your answers.	
Q11	Do you agree these considerations should be taken into account under an exacerbators pay approach? Please provide an explanation in support of your view.	
Q12	Do you agree that these ways can be used to identify beneficiaries? Are there others? If so, please provide details.	
Q13	Do you agree with the assessment of the price that should apply to beneficiaries? Do you agree with the assessment of how beneficiaries pay should apply in practice? Please provide an explanation in support of your answer.	
Q14	Do you agree that prima facie the increase in transmission costs in the next few years may provide incentives for some direct connect customers to disconnect from the grid? Please provide any evidence and an explanation in support of your answer.	
Q15	Are there other alternative pricing options? Do you agree with the assessments of how incentive free and postage stamp pricing should be applied in practice? Please provide reasoning in support of your answer.	

Appendix B The economic possibility of grid disconnection

B.1.1 A worldwide market exists for second-hand 10-80 MW diesel/gas turbine generators. Purchasers of such plant include remote mining operations, embedded generation, and industrial users.

B.1.2 From the recent sale of the Whirinaki plant we know that the market price of such a second-hand diesel generator in New Zealand is $33 million for 155 MW capacity, or $0.2129 million per MW or $212.90 per kW. If we assumed a 50% uplift in cost to relocate the plant, straight-line depreciation over 25 years, a cost of capital of 15% per annum, and that the plant will operate 1% of the time as a back-up at a cost of $370/MWh above the market price of electricity ($80/MWh), the cost of diesel generator back-up is $93/kW per year. At a utilisation rate of 3%, the cost of standby generation is $158/kW per year.

B.1.3 In the 2011/12 pricing year, Transpower's annual interconnection rate was set at $76.14/kW and its HVDC rate at $36.58/kW.[31] The total of these two figures is $112.72/kW per year. These charges do not cover connection costs, which vary between installations but are currently similar in aggregate to the HVDC charge, indicating an average of around $35/kW per year. In November 2011, the Commerce Commission approved increases in Transpower's regulated revenue of 27.1%, 15.6% and 5.8% in the years 2012/13, 2013/14 and 2014/15.[32] If these percentage increases are applied to the sum of the interconnection and HVDC rates in 2011/12, the resulting very rough estimates for these charges in the 2012/13 – 2014/15 years are: $143.26/kW, $165.61/kW and $175.22/kW.

B.1.4 These figures can be compared with the estimates of the costs of standby generation as back-up of $93/kW and $158/kW at 1% and 3% utilisation. When this is done, and allowance is made for the likelihood a currently directly connected customer could save some connection charges by disconnecting from the grid, it appears to the Authority to be a very real possibility that it will be in the interests of some large consumers with co-generation plant to disconnect from the grid rather than face the price rises the Commerce Commission has approved for Transpower.

B.1.5 This risk would be increased if, as the majority of TPAG favoured, the HVDC charge is levied on consumers. The prudent discount policy in the current TPM explicitly excludes payments in lieu of investing in additional generation and, therefore, would not be applicable should a consumer's proposal be to install a back-up plant and disconnect from the grid.

31 http://www.transpower.co.nz/f5453,63579601/appendix-2-transmission-pricing-2012.pdf

32 http://www.comcom.govt.nz/maximum-allowable-revenues-2012-13-2014-15/

B.1.6 As regards the materiality of this possibility, the Authority notes that, in 2010, 37.7% of New Zealand's electricity consumption was by industrial users[33] and took place through only 2.0% of the country's Installation Control Points (ICP's).[34] Moreover, in 2010, 9.9% of the North Island's electricity generation occurred in co-generation plants.[35]

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[33] MED, Energy Datafile, 2011, Table G.5a

[34] MED, Energy Datafile, 2011, Table G.5b.

[35] MED, Energy Datafile, 2011, Table G.2d.