



Transmission pricing methodology review

Overview of issues and the Electricity Authority's proposal

10 October 2012

Introduction

1. The Electricity Authority (Authority) is reviewing the transmission pricing methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover costs of providing transmission services.
2. The Authority considers that the current TPM can be improved so as to better promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.
3. This paper is a companion to the issues paper published by the Authority under the Electricity Industry Participation Code 2010 (Code). The purpose of this paper is to provide an overview of transmission pricing, of the Authority's proposal, and of the process the Authority will follow during this review of the TPM. Of necessity, the overview paper does not include all of the information in the issues paper. Some information may be presented in summary form or omitted altogether. Readers seeking an in-depth understanding of the issues, and those who wish to make fully-informed submissions, are referred to the issues paper which is available at <http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12>.

Context of transmission pricing

Transmission costs are increasing

4. The current TPM is set out in the Code, which is administered by the Authority. The purpose of the TPM is to ensure that, subject to the Commerce Act 1986, the full economic costs of Transpower's services are allocated in a way that promotes competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.
5. The TPM has evolved through several iterations since 1988, with change driven by changes to the electricity industry structure, development of electricity markets and advances in technology. There have been regular calls to alter the allocation of transmission costs and industry participants have in the past legally challenged the process for developing the TPM.
6. The amount that Transpower can recover for providing transmission services is determined by the Commerce Commission. Annual transmission costs are expected to increase by 79 per cent over the coming decade, from \$624 million in 2010/11 to \$1.1 billion in 2019/20, due to a significant capital investment programme to upgrade the transmission system.

The Authority's objective for the TPM is overall efficiency in the electricity industry

7. The Authority considers that the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers by facilitating:
 - (a) efficient investment in the electricity industry through providing incentives so that the right investments occur at the right time and are in the right place. These investments can be in the transmission grid, generation (including distributed generation), distribution networks or demand-side infrastructure to manage electricity consumption; and
 - (b) efficient operation of the transmission grid, generation (including distributed generation), distribution networks and demand-side management. This means providing incentives so that the day-to-day operation of transmission, generation, distribution and demand-side management involves an efficient trade-off between reliability and cost.
8. Efficient participation in the regulation of the TPM is also a key consideration. The TPM has been subject to considerable debate, lobbying and court action over many years. Establishing a robust and durable approach to the TPM will (1) improve efficient investment in the electricity industry by reducing regulatory risk regarding the on-going prospect of changes to the TPM and (2) improve efficient operation of the electricity industry by increasing productivity through reducing the inputs required to lobby and review the methodology.

Market prices generally reflect differences in the cost of supply

9. Markets establish prices for goods and services through the interaction of buyers and sellers. A buyer will not pay more than a good or a service is worth to them and a seller will not succeed in charging more than the buyer's benefit.
10. In competitive markets, competition forces sellers to charge prices at levels reflecting the marginal cost of supply. Prices vary by location, date and time of delivery, and type of customer, when the cost of supply is affected by those factors. These prices are efficient and are widely accepted by buyers and sellers alike.

Markets generally ensure parties benefiting from a service pay for the service

11. Normally prices reflect cost but where firms have a high level of shared costs (called common costs) prices are often linked to the private benefits different types of customers are likely to gain from a service.
12. For example, entry prices to theme parks often differ substantially for local residents (who can visit often), for seniors (who may not get as much private benefits as the active population), and for students and large families (who may be more budget-constrained than the general population). In each case prices are targeted roughly by the willingness of categories of consumers to pay for the service, and this practice is widely accepted by consumers.
13. In short, markets ensure parties benefiting from a service pay for those services, and parties that don't benefit don't pay. Payment is inextricably linked to parties benefiting from a service (called **beneficiaries** in this paper), to variations in the cost of supply and, in many situations, to the private benefits of consumers. The primary exception to this rule is when the production or consumption of a service has passive flow-on benefits or costs for other parties (called **externalities**).

The current TPM does not establish efficient prices

14. The current TPM comprises three main types of charges:
 - (a) a *connection charge*, to recover the cost to Transpower of connecting parties to the transmission grid;
 - (b) an *HVDC charge*, to recover the cost of the high voltage direct current (HVDC) link between the North Island and the South Island; and
 - (c) an *interconnection charge* which, in simple terms, recovers the cost of the interconnected grid in the North Island and in the South Island.
15. The amount of revenue collected through these charges are currently about:
 - Connection charge: \$129 million
 - HVDC: \$129 million
 - Interconnection \$547 million
16. The connection charge is largely based on the commercial interaction of the connecting party and Transpower, but with regulated components to provide a backstop against deadlocked commercial negotiations. The Authority calls this a **market-like charge** because it closely resembles the market approach discussed above.
17. The Authority believes the current HVDC and interconnection charges are not efficient as the charges bear little relationship to the costs and benefits of HVDC and interconnection services.
18. In particular, many parties do not have strong incentives to ensure that transmission investment decisions only deliver the transmission service they want, because those parties are not required to pay the full cost of the investment and service. This is because the costs may be borne by other parties who do not derive an equivalent private benefit. The Authority considers that there are substantial efficiency gains to be made from pricing that promotes better targeted and better timed investment in transmission, generation and demand-side management.

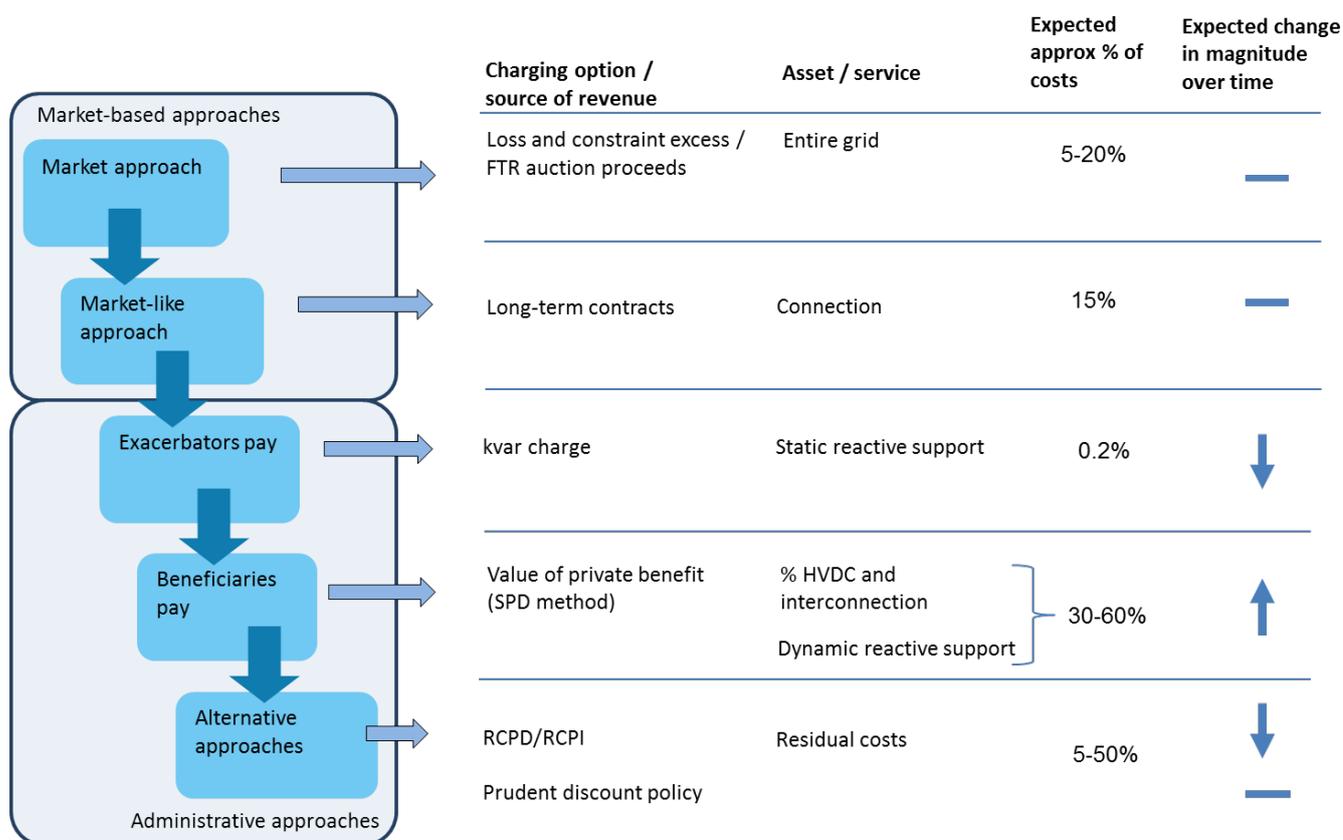
Current HVDC and interconnection charges are inflexible and not durable

19. The HVDC and interconnection charges are the most contentious components of the TPM. The connection charge is generally not contentious as parties can readily verify the costs of supply and they accept they should pay for assets that directly benefit them. In contrast, the benefits of HVDC and interconnection services are indirect, the costs attributable to each user are hard to determine, and historically the methods used to recover these costs have not been closely linked to the benefits parties receive from them.
20. The Authority believes that parties generally accept charges when they can see the link between the charges they pay, the cost of service to them and the benefits they receive. This is not the case with the current HVDC and interconnection charges, which have been reviewed multiple times since 1994. Potentially affected parties have spent considerable time and resources lobbying and issuing legal challenges. The potential for continuing change does not provide an environment that promotes efficient investment.

The Authority’s proposal – the party that benefits should pay

21. The Authority is proposing that the TPM comprise a package of approaches to establish charges for transmission services that reflect the market principles for pricing discussed earlier in this overview.
22. The Authority’s proposal allows transmission charges to automatically shift over time with changes in grid use and configuration, without the need to fundamentally review the methodology. The Authority believes the flexibility of this approach, and the explicit link to private benefits, should create a durable approach to the TPM and reduce future costs of lobbying and legal challenges related to the TPM. The proposal should also provide efficiency benefits by reducing the frequency with which the TPM needs to be reconsidered due.
23. The Authority’s proposal for recovering the costs of transmission services is set out in Figure 1.

Figure 1: Overview of TPM proposal



Explanation of technical terms/acronyms in Figure 1

kvar	kilo volt-ampere reactive, a measure of reactive power in an AC (alternating current) system. (Reactive power supports the voltage which is needed for reliably operating the system. This is different from real power, which is what people usually think of as “power”, which provides heat, light and motive power.)
Static reactive support	Steady state voltage management which provides support to compensate for on-going reactive power issues.
SPD	Scheduling, Pricing and Dispatch model, or the wholesale electricity market model.
Dynamic reactive	Maintains voltage within acceptable limits in the milliseconds following unexpected outages

support	and helps avoid widespread loss of supply.
RCPD/RCPI	Regional coincident peak demand / regional coincident peak injection.

24. The Authority’s proposal also includes a Prudent Discount Policy (PDP).

Surplus spot-market funds are available to partially offset transmission charges

25. Access to the transmission grid is currently rationed on a five-minute basis by the operation of the wholesale electricity spot market. A computer model, called the scheduling, pricing and dispatch (SPD) model is used to dispatch generation resources for five-minute periods based on the half-hourly offer prices submitted by generators.
26. The SPD model dispatches generation by taking into account security constraints in the grid and estimated energy losses from transmitting electricity from grid injection points to grid exit points. The presence of losses and constraints results in spot-price differences across the grid, and produces surplus funds (called **loss and constraint excess**¹) that the clearing manager transfers to Transpower.
27. In effect, the spot market already provides a **market approach** to paying for transmission services. Currently, Transpower pays the loss and constraint excess to transmission customers in proportion to their transmission charges. In the customers' hands, the loss and constraint excess reduces the net amount they pay to Transpower.
28. The Authority proposes to codify the current arrangements. The loss and constraint excess (and in the future, surplus financial transmission right auction proceeds) received by Transpower from the clearing manager are to be used to offset the components of Transpower’s transmission charges that correspond to the origin of the loss and constraint excess. For example, the amount of loss and constraint excess received by Transpower and applied to offset the costs of the assets being built as part of the North Auckland and Northland (NAaN) project would correspond to the loss and constraint excess originating on the NAaN assets.
29. In principle, the loss and constraint excess could fully fund the costs of transmission assets. In practice, a large funding deficit (or residual) occurs because grid investments typically have spare capacity to achieve economies of scale. In the short term there is under-utilisation of that spare capacity. Even without economies of scale, a large deficit occurs if grid investments are made earlier than is justified on economic grounds. It is therefore necessary to recover this deficit through other charges.

Recovering the cost of connection services

30. The Authority considers that the arrangements for obtaining and providing connection services are generally operating effectively and promote efficient investment in the electricity industry. The costs of connection services are recovered through long-term contracts, which is a **market-like approach**.
31. However, there are aspects of connection charging that provide connecting parties with inefficient incentives to minimise their connection costs by shifting some connection costs into the

¹ The loss and constraint excess is also referred to as “loss and constraint rentals” or “transmission rentals”.

interconnection charge. These problems reflect relatively minor drafting deficiencies (loopholes) in the current TPM.

Proposal for connection services: status quo but limit the shifting of connection costs into the interconnection charge

32. The Authority proposes retaining the status quo for recovering the costs of connection services, except to limit the shifting of connection costs into the interconnection charge. This approach would retain and improve the market-like arrangements for connection services. The proposal is:
- (a) for the TPM to require that current connection assets be treated as connection assets until they are replaced or decommissioned;
 - (b) for the TPM to require that replacement assets are valued for charging purposes at the actual replacement project cost; and
 - (c) for the Benchmark Agreement to include a mechanism for a connection customer to apply to the Authority to determine any connection charges the connection customer considers had been set at an unreasonable level as a result of asset replacement.

Recovering the cost of network reactive support services

33. Network reactive support services involve dynamic reactive support and static reactive support. The Authority considers that the need to invest in static reactive support equipment is the result of an externality, which arises because parties are using power in a manner that results in a poor power factor for other transmission users.
34. The Authority considers the most efficient approach to recovering the costs of an externality is to charge the parties exacerbating the externality through their actions or inactions. This is called an **exacerbators-pay approach**.

Proposal for static reactive support services: kvar charge with minimum power factor

35. The Authority proposes to establish a specific exacerbators-pay charge to recover the costs of static reactive support services. The proposal is:
- (a) for the TPM to include a kvar charge based on the aggregate kvar draw of off-take transmission customers, at times of regional coincident peak demand, in areas of the grid where investment in static reactive support is likely to be required; and
 - (b) to set the kvar charge at the long-run marginal cost of grid-connected static reactive support investment.
36. The Authority also proposes that a minimum power factor of 0.95 lagging for all regions is set in the Connection Code.²
37. The proposal will provide parties with incentives to only draw reactive power when and where this is efficient or to invest in equipment to manage their reactive power use.

² The Connection Code, which is incorporated by reference into the Code, specifies the requirements for Transpower and transmission customers in relation to connections to the grid.

Proposal for dynamic reactive support services

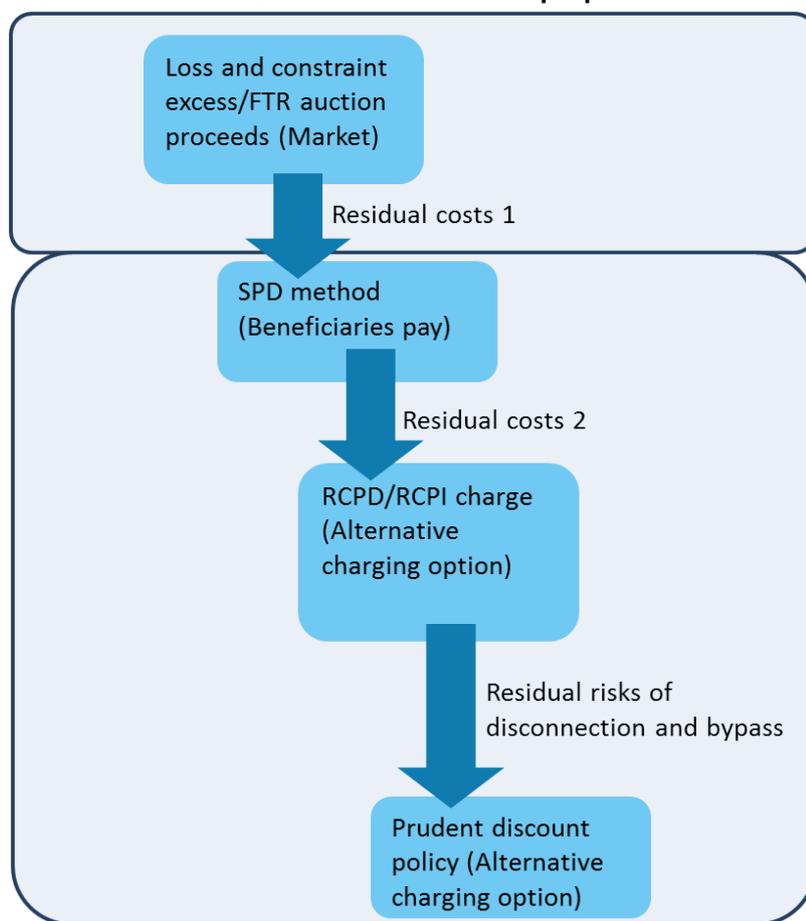
38. The Authority does not consider that a separate charge is required for dynamic reactive support services because there is no externality in providing this service. Consequently the Authority considers that the costs of dynamic reactive support should be recovered through the HVDC and interconnection charges.

Recovering the costs of HVDC and interconnection services

39. The Authority's proposal for recovering the costs of HVDC and interconnection services has four parts:
- (a) Part 1: (as discussed above) to codify the current arrangements in which the loss and constraint excess (and in the future, surplus financial transmission right auction proceeds) received by Transpower from the clearing manager are to be used to offset the components of Transpower's transmission charges that correspond to the origination of the loss and constraint excess;
 - (b) Part 2: for the TPM to require the scheduling, pricing and dispatch (SPD) model³ to be used first to identify the beneficiaries of certain HVDC and interconnection investments, and second to estimate the extent of the private benefits they receive from those investments on a half-hourly basis (referred to as the SPD method). The beneficiaries identified by this method would be charged for the cost of each investment in proportion to their share of the benefits of each investment, but with the amount of this part of the charge not exceeding their private benefit in each case;
 - (c) Part 3: for the TPM to require Transpower to apply a regional coincident peak demand (RCPD) charge to load and regional coincident peak injection (RCPI) charge to generation parties to recover the residual balance of the costs of the HVDC and interconnection assets not recovered by other charges. The RCPD and RCPI charges should be set so that each raises half the residual balance. They should also be designed so that parties subject to the charge have efficient incentives to avoid peak use of the grid in each region; and
 - (d) Part 4: for the TPM to include a PDP to enable Transpower to develop a PDP that would apply to the expected life of the asset (currently only 15 years) and to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges. The purpose of these proposed changes is to better deal with the possibility of inefficient bypass of the grid or inefficient disconnection from the grid.
40. The Authority's proposal for recovering the costs of HVDC and interconnection services, together with the relationship of each element to the Authority's economic framework for the TPM, is set out in Figure 2.

³ Alternatively, the vectorised SPD (vSPD) model developed by the Authority could be used for this assessment. Accordingly, where this overview paper refers to SPD this should be read as "SPD or vSPD".

Figure 2: Overview of HVDC and interconnection proposal and relationship to economic framework



Proposal (part 1): Surplus spot-market funds are available to partially offset transmission charges

41. As discussed in paragraphs 23-27, the Authority proposes to codify the current arrangements in which the loss and constraint excess (and in the future, surplus financial transmission right auction proceeds) received by Transpower from the clearing manager is used to offset the components of Transpower’s transmission charges that correspond to the origination of the loss and constraint excess. This would offset a portion of the costs of HVDC and interconnection assets but, as discussed, a large funding deficit occurs because grid investments typically exhibit large economies of scale and when grid investments are made earlier than is justified on economic grounds.

Proposal (part 2): use the SPD method to set beneficiaries-pay charges for HVDC and interconnection services

42. When a market-based charge is not possible and an administrative charge is necessary, a key principle for services with high common costs is that “parties that benefit should pay”. This principle is not new, or unique to New Zealand. A similar concept was developed by the Transport Working Group of the Electricity Governance Establishment Board in 2002. Case law from the United States of America has established that the Federal Energy Regulatory Commission (FERC) cannot approve a transmission pricing scheme that requires parties to pay for facilities from which they derive no benefits, or face charges where the benefits to them are trivial in relation to the costs

sought.⁴ These principles were adopted by FERC in Order No. 1000, issued in July 2011, and recently confirmed after considering submissions on the proposed arrangements.⁵ This is called a **beneficiaries-pay charge**.

Methods for applying beneficiaries-pay charges

43. The key issue for the beneficiaries-pay charge is deciding what method to use to identify the beneficiaries of a transmission asset and to determine the private benefit they gain from the asset.
44. There are diverse methods for identifying the benefit derived by parties from transmission services, ranging from rough approximations to sophisticated economic models.
45. The Authority considers that wholesale electricity market outcomes, assessed using the SPD model, provide the best available method for implementing the beneficiaries-pay charge. The beneficiaries identified by this method would be charged for the cost of each investment in proportion to their share of the private benefits from each investment, but with the maximum charge not exceeding their private benefit in each case.
46. The beneficiaries-pay charge would apply to the parties identified as benefiting from the transmission assets through wholesale market outcomes, as determined by the SPD model. The charge would apply to all parties offering to supply to, or purchase from, the wholesale market. The Authority proposes that the charge would be calculated each trading period and charged on a monthly basis.
47. The Authority proposes that the beneficiaries-pay charge should not apply to the costs of all transmission assets. The proposed cut-off date is 28 May 2004, the date when Part F of the Electricity Governance Rules 2003 came into force. Costs relating to assets built prior to this date would be recovered through a residual charge. The one exception to this is pole 2 of the HVDC link, which the Authority considers should also be subject to a beneficiaries-pay charge so that the charging basis for pole 2 is broadly consistent with the charging basis for pole 3.
48. The Authority also proposes an investment-cost threshold for applying the SPD method, below which costs would be recovered through a residual charge. The proposed threshold would be \$2 million.
49. The costs of interconnection assets not covered by the beneficiaries-pay charge (i.e. assets built before 28 May 2004 or below \$2 million) would be recovered through the residual charge.
50. The proposed SPD method represents a significant departure from the current hybrid arrangement of: (a) a postage stamp charge approach to recovering the costs of interconnection assets; and (b) South Island generators paying for the HVDC charge. However, the SPD method is much more closely aligned with a beneficiaries-pay approach and accordingly would deliver significant efficiency benefits.

The SPD method should provide reasonable estimates of private benefits

51. The Authority's view is that designing a perfect beneficiaries-pay charge is not possible with current technology, and it is not attempting to do so. The key issue for the Authority is whether the proposed beneficiaries-pay charge delivers greater economic benefits for consumers than any

⁴ Illinois Commerce Commission v FERC, 576 F.3d 470, 476 (7th Cir., citations omitted), available at, <http://www.ferc.gov/legal/court-cases/opinions/2009/PT1FG750-opinion.pdf>.

⁵ FERC, Order No. 1000 – transmission planning and cost allocation, more information is available at: <http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp>.

other lawful alternative that is available. All transmission pricing options involve approximations and compromises, and the SPD approach to implementing beneficiaries pay is no different.

The SPD method brings transparency to investment decision making

52. The Authority believes generators – and consumers once dispatchable demand is introduced – will try to structure their offers to the spot market to minimise the estimation of their private benefits from specific grid assets.
53. For example, South Island generators could avoid the beneficiaries-pay charge for pole 3 of the HVDC by offering on the basis of pole 2 alone being available. Rather than being a problem, the Authority believes this is a positive attribute of the proposal, viz:
 - (a) if successful, the revised offering behaviour would reveal that pole 3 was not economically justified and does not deliver private benefits to South Island generators. The costs of pole 3 in this case should be recovered from market participants receiving private benefits from pole 3 (if any) or through the residual charge that is analogous to a 'broad-base low rate' tax on market participants and consumers for uneconomic grid investments; and
 - (b) alternatively, if South Island generators were unable to structure their offers to avoid the beneficiaries-pay charge then this suggests pole 3 delivers private benefits for them and they should pay for the costs of pole 3 (but capped at the level of their private benefits).

The SPD method provides a highly flexible and durable beneficiaries-pay charge

54. Another key advantage of using the SPD model is that the beneficiaries-pay charge would vary in accordance with variations in the benefits each party receives.
55. For example, if there is significant growth in electricity demand in the North Island that would be met by increased South Island generation, South Island generators would receive larger benefits from pole 3 on the HVDC link. Under the SPD method, South Island generators would automatically pay a larger share of the costs of pole 3. Similarly, any additional transmission investment required in the South Island to get the surplus power to the North Island would automatically be paid by South Island generators benefiting from those investments.
56. This flexibility should greatly reduce the need to fundamentally review the TPM in the future, bringing lower regulatory costs in the form of reduced lobbying activity and legal challenges, lower administrative costs associated with on-going reviews of the TPM and lower regulatory uncertainty for investors (transmission customers).

Proposal (part 3): a residual charge is needed to recover remaining transmission costs

57. The surplus spot-market funds (loss and constraint excess) and the beneficiaries-pay charge are unlikely to fully recover costs of HVDC and interconnection services. Consequently, a second residual occurs, which the Authority is proposing to recover through a broad based low rate or uniform charge. The residual charge will be set to ensure full recovery of Transpower's maximum recoverable revenue, which is set by the Commerce Commission after receiving draft calculation of forecast revenue from Transpower.
58. A uniform charge is analogous to a tax or levy because there is no direct relationship between the amount paid, the cost of supply for individual components and the benefit grid users derive from them. The Authority thinks that a uniform charging approach would not be efficient and should not

be preferred if transmission charges can be funded from loss and constraint excess and the beneficiaries-pay charge.

59. The Authority proposes that the residual charge should be levied on both demand (using regional coincident peak demand, or RCPD) and generators (using regional coincident peak injections, or RCPI). The charge would be designed to encourage efficient avoidance of peak regional use of the grid; it is intended that the residual will be collected half from load and half from generation. The residual charge should:
- (a) apply to generation as well as load; and
 - (b) in principle, be applied to electricity retailers as well as direct connect customers.

RCPD/RCPI charge designed to encourage efficient avoidance of peak regional use of the grid

60. The Authority proposes that the residual charge would consist of an RCPD/RCPI charge and that Transpower would determine:
- (a) the optimal regions for applying the charge; and
 - (b) the number of regional coincident peaks for load and generation in each region to determine the charge that would apply. The number of peaks should reflect what is necessary to encourage efficient avoidance of peak use of transmission in each region.
61. Further, the Authority proposes that Transpower would review the number of peaks every three years to ensure that the charge was efficient and this would be subject to review by the Authority.

Parties that should pay a residual charge

62. The Authority considers that the residual charge should be applied to generators, direct-connect customers and distributors (or retailers). The Authority considers that distributors should have the ability to opt out of the residual charge, meaning that the retailers operating on that distribution network would pay the residual charge. A distributor would not be able to opt-out of the residual charge to the extent that they benefited from offering to or purchasing from the wholesale electricity market. A distributor's ability to opt out would also be subject to consulting with retailers on their network.

Proposal (part 4): a prudent discount policy is needed as no transmission charge is perfect

63. All charging methods require compromises to make them practicable and to manage transaction costs. The Authority recognises that the TPM proposal could result in a party inefficiently bypassing or disconnecting from the grid by investing in generation. The current TPM mechanism has a means to address this issue called the "prudent discount policy", which provides for a transmission customer's transmission charges to reflect the costs of the project the customer would undertake if they chose to bypass the grid.
64. The Authority proposes that the prudent discount policy be extended to provide Transpower with the ability to apply a prudent discount when generators or load seek to reduce their transmission charges by bypassing or disconnecting from the grid. In particular, it is proposed the prudent discount policy be amended so that it:
- (a) would apply for the expected economic life of the asset for which a prudent discount is sought; and

- (b) would apply to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges but the investment would be inefficient from an economy-wide point of view.

TPM proposal cost benefit analysis

65. The Authority has undertaken a cost-benefit analysis of the TPM proposal against the current TPM. The Authority has also undertaken cost-benefit analysis of the option preferred by the majority of the Transmission Pricing Advisory Group (TPAG) against the counterfactual of the status quo to assess whether the Authority's proposal delivers larger net economic benefits. The TPAG minority view was to retain the current TPM arrangements for recovering HVDC and interconnection costs.
66. The cost-benefit analysis estimates the net present value of the economic costs and benefits from the Authority's proposal and the TPAG majority view over a 30-year period using a discount rate of 6.01 per cent (real terms), pre-tax.
67. The overall results of the analysis, for the central case, are provided in the Table 1 below.

Table 1: Summary of aggregate costs and benefits (central case)

PV of economic costs and benefits	EA proposal
Economic costs	\$50.1m
Economic benefits	\$223.3m
Net economic benefit	\$173.2m

68. Sensitivity analysis of the costs and benefits for the Authority's proposal presented in Table 2. This provides sensitivity analysis for two cases: optimistic (low costs and high benefits) and pessimistic (high costs and low benefits).

Table 2: Optimistic and pessimistic sensitivity analysis (aggregated)

Sensitivity of economic costs and benefits PV	EA proposal (Optimistic)	EA proposal (Pessimistic)
Economic costs	\$32.0m	\$81.0m
Economic benefits	\$300.7m	\$166.1m
Net economic benefits	\$268.7m	\$85.0m

69. The sensitivity analysis suggests the Authority's proposal is robust to alternative assumptions. Accordingly, the Authority considers that its proposal is likely to deliver significant net economic benefits relative to the status quo.

Details of issues and proposal

70. The Authority's proposal for the TPM is described in the Transmission Pricing Methodology: issues and proposals consultation paper, available at <http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12>.

71. The Authority's proposal for the TPM is detailed in chapter 5, and alternative options considered by the Authority are summarised in chapter 6. Draft guidelines for Transpower to develop the proposed TPM are set out in chapter 7 while a proposed process for Transpower to follow in developing the TPM are set out in chapter 8.

Process for reviewing the TPM

72. Subpart 4 of Part 12 of the Code sets out a process for reviewing the TPM. The Authority is adopting a process consistent with the Code process, involving:
- (a) publishing an issues paper that contains the proposed process and the proposed guidelines for Transpower to follow in developing a new TPM. The issues paper also seeks feedback on the Authority's assessment of the nature and materiality of the problems with the current TPM and the Authority's proposal for the TPM;
 - (b) considering feedback received on the issues paper. The Authority may allow for a further round of consultation to seek feedback on issues raised through submissions for further analysis;
 - (c) determining the final guidelines and final process for Transpower to follow in preparing a TPM;
 - (d) requesting Transpower to submit a proposed TPM. Clause 12.79 of the Code requires Transpower, in developing a TPM, to assess the TPM against the Authority's objective;
 - (e) considering the proposed TPM and either approving the TPM for consultation (in certain circumstances the Authority may request Transpower to resubmit a revised TPM before approving the TPM for consultation) or amending the proposed TPM before the TPM is published for consultation; and
 - (f) consulting on the proposed TPM as soon as practicable. As the TPM is a schedule to the Code, the Authority's consultation must meet the requirements of section 39 of the Electricity Industry Act 2010.
73. The Authority will make a decision on the proposed TPM (including the commencement date) after considering submissions on the proposed TPM. Clause 12.79 of the Code states that the Authority will assess the TPM against the Authority's statutory objective.

Submissions are requested by 30 November 2012

74. The Authority invites interested parties to make submissions by 5pm on Friday, 30 November 2012. Please note that late submissions are unlikely to be considered.
75. The Authority invites interested parties to make cross-submissions, and these should be received by 5pm on Friday, 21 December 2012. Please note that late cross-submissions are unlikely to be considered.

Forums are being held

76. The Authority will hold forums in Auckland, Wellington and Christchurch to give interested parties the opportunity to ask questions about the Authority's proposals and analysis for the transmission pricing methodology on the following dates:
- (a) Wellington – 17 October 2012;

(b) Christchurch – 18 October 2012; and

(c) Auckland – 19 October 2012.

77. The Authority will announce further details of the forums through the Market Brief publication on its website. Interested parties can register by emailing info@ea.govt.gov.nz, advising your name, organisation and the forum you are interested in attending.