TRANSPOWER NEW ZEALAND LIMITED

Cross Submission on Submissions Received on the Transmission Pricing Methodology Consultation Paper

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1. Introduction

This is Transpower's cross submission in response to submissions received by the Electricity Commission on the Commission's *Transmission pricing methodology consultation paper*, 1 November 2006.

2. Scope of the consultation and possible amendments to the TPM

The Commission and Transpower both have roles in developing the transmission pricing methodology (TPM). These roles are articulated in rule 2 of section IV of Part F. Transpower's role is to develop the TPM (i.e. act as its primary author), while the Commission's role is to assess the TPM to ensure that it adequately conforms to the requirements of rule 7.2.1 and approve the TPM if it does. In practice, the requirements of rule 7.2.1 are consistency with the pricing principles set out in rule 2 of section IV, the application and interpretation of these pricing principles as described in rule 3 and consistency with the Commission's transmission pricing guidelines.

It is clear from the scheme of section IV of Part F that the focus of the consultation process must be consistency with the guidelines and the pricing principles. The Commission has "approved" the TPM in accordance with rule 8.1.1.1, meaning that it has found that the TPM adequately conforms to the requirements of rule 7.2.1. At this stage in the process, the Commission may only make substantial changes to the TPM if it can be satisfied that in one or more respects the proposed TPM does not adequately conform. The purpose of the current consultation is to provide submitters with an opportunity to bring to the attention of the Commission possible instances of non conformance to the requirements of rule 7.2.1.

A number of submissions have raised issues relating to the content of the pricing principles and the guidelines. For example, some submissions propose that the methodology for the interconnection charge should be based on a long run marginal cost based approach. However, when it originally created the guidelines in December 2004, the Commission rejected this approach and specified that the charges for interconnection assets should be on a postage stamp basis (while at the same time indicating that it intended to undertake further work on locational pricing).

Other submissions challenge the requirement in guideline 15 that the costs of the HVDC link be charged to all South Island generating stations that inject into the grid. The Commission has undertaken a lengthy consultation on this matter and explained its conclusion in detail. That decision is clearly outside the scope of this consultation.

Some submissions put forward alternative ways of complying with the pricing principles and guidelines but do not explain how the existing proposals fail to comply adequately with the pricing principles and guidelines. There are always alternative ways to allocate sunk costs and it is usually impossible to demonstrate objectively that one is superior to another.

In Transpower's view submissions that go to the content of the pricing principles and/or the guidelines are not relevant considerations for the Commission when determining whether or not to confirm its approval of the TPM proposed by Transpower. The pricing principles are contained in the rules and the guidelines have been the subject of a separate consultation process. The current consultation on the TPM does not present an opportunity for parties to re-litigate requirements that are already reflected in the rules or, in the case of the guidelines, documents established under the rules.

Similarly, Transpower considers submissions that put forward alternative ways of complying with the pricing principles and/or the guidelines are also no longer relevant considerations.

The key question for the consultation process under rule 8 of section IV is whether the TPM proposed by Transpower adequately conforms to the requirements of rule 7.2.1 (i.e. whether the TPM proposed by Transpower is inconsistent with the pricing principles and the guidelines).

Transpower notes the Commission's statements in sections 3.5.1 and 3.5.2 of the consultation paper¹ that rule 7.2.1 contains an absolute requirement that the proposed TPM be consistent with the guidelines, that the guidelines are not being revisited at this stage and have been set taking into account the same regulatory criteria as are now being considered in respect of the proposed TPM itself. The guidelines require specific features of the TPM to exist (e.g. interconnection charges should be on a postage stamp basis). Consequently, the proposed TPM has been assessed against the guidelines first, and only where the guidelines are less specific has a more complex assessment against the pricing principles and other Commission outcomes and objectives been undertaken. Transpower agrees with these comments.

3. Timeline for implementation

In July 2006, the Commission decided that the timeline for implementing the TPM and the related Benchmark Agreement and Interconnection Rules was a sufficiently important matter to warrant consultation. Following consultation, the Commission's decision was that the common implementation date for the TPM, Benchmark Agreement and Interconnection Rules should be 1 April 2008. As part of its decision, the Commission also published a timetable of actions which would enable this implementation date to be achieved. The timetable stated that the recommendation on the TPM to the Minister of Energy would occur in June 2007. Transpower has begun a programme of work needed to implement the new TPM in accordance with the Commission's decision and the published timetable. As this work requires commercial expenditure, Transpower urges the Commission to adhere to its published timetable and its decision on the common implementation date.

The remainder of this cross submission comments on some of the points made by other submitters, particularly in relation to suggested modifications to the proposed TPM.

4. Revenue setting and allocation

The TPM is an allocation methodology only. Transpower's revenue is set outside the TPM and regulated in accordance with Part 4A of the Commerce Act 1986. The proposed TPM makes this distinction clear.

One submitter has queried the need to specify separately an HVDC revenue and an AC revenue outside the methodology and suggested that the TPM itself should allocate a single total revenue between connection, HVDC and interconnection charges. This submitter suggested that such an approach is required by guideline 5.

Guideline 5 requires Transpower to detail the "linkages between its charges for specific assets, its overall expected revenue and allocation of this to specific grid connection points". There is no suggestion that this has not been done. Transpower does not agree that guideline 5 can be read as requiring a single revenue requirement. Although, in principle, it would be possible for Transpower to determine a single revenue requirement (given that the asset valuation methods and weighted average cost of capital (WACC) are common between HVDC and AC assets) such an approach presents practical problems. In particular, there are currently separate EV accounts for HVDC and AC assets, which contain substantially different balances, one positive and one negative. If a change were to be made to having only a single revenue requirement to be allocated by the TPM, there would only be one EV account and this would substantially disadvantage AC customers. Conceptually, EV adjustments could be incorporated into the TPM, but this would not only add unnecessary complication to the TPM but also directly breach the principle that the TPM should be an allocation mechanism only

¹ Transmission pricing methodology consultation paper, Electricity Commission, 1 November 2006

and revenue setting should occur outside the TPM. On this point, it should be noted that guideline 3 refers to the allocation of Transpower's full economic costs, not the determination and allocation of those costs.

Concern has also been expressed that the proposed TPM appears to give Transpower the freedom to set its own WACC by referring to "the WACC used by Transpower". In fact, Transpower's WACC, along with the other elements of revenue setting, are subject to regulatory oversight, but this is done outside the TPM and in accordance with Part 4A of the Commerce Act.

5. Asset valuation method

Some submissions have expressed the view that the ODV valuation method should continue to be used to value Transpower's system fixed assets, and that it may be premature to propose allocation methods based on the physical grid or to argue that changing the connection asset allocator from ORC to RC is expected to be essential in practice, because optimised values are unlikely to be available in the future.

On 13 October 2005, the Commerce Commission published the following "in principle" decisions on the asset valuation method for Transpower's system fixed assets²:

- The Commission has in principle decided that system fixed assets for Transpower be valued using an Indexed Historical Cost method (para. 15)
- The Commission intends to develop a Handbook for the application of an Indexed Historical Cost method for Transpower, taking account of independent expenditure review processes already in place (para. 16)
- The Commission's proposal will not allow Transpower to choose a different valuation method (para. 17).

Irrespective of the outcome of administrative settlement discussions with the Commerce Commission, it is envisaged that an historical cost based valuation method will replace ODV as the method used to value Transpower's system fixed assets. Transpower has previously advocated the use of a depreciated rather than indexed historical cost method, but this change is the subject of ongoing discussions between Transpower and the Commerce Commission on an administrative settlement.

6. Audit requirements

The audit requirements for the TPM are contained in section IV of Part F of the Electricity Governance Rules. Consequently, there is no need for audit requirements to be specified in the TPM as some submitters have suggested.

7. Connection Charges

7.1 Definition of connection/interconnection

A number of submitters have suggested that there should be a common definition of "connection"/"interconnection" and "non-core"/"core" to describe grid assets.

The purpose of defining "connection" is to identify AC assets for which specific users can be identified, whereas the "non-core" definition is aimed at identifying assets that are not critical to maintaining grid security standards. Although consistency might have some advantages if it were possible, the fact that the purposes of the two concepts are different suggests that two separate definitions should remain. In any event, it would not be possible to equate connection assets with the Commission's definition of "non core" assets and achieve conformity with the guidelines and pricing principles, because the "non core" assets include

² Regulation of Electricity Lines Businesses – Valuation of the Regulatory Asset Base Decision Paper, Commerce Commission, 13 October 2005, paras. 15-18

many interconnected assets through which loop flows are possible. Outside of small regional loops, it is usually impossible to identify clearly the users or beneficiaries of such assets.

Another difference between the ways in which the two definitions are used is that "connection" is used to define connection assets, which may be located at a connection node or an interconnection node (and, conversely, there may be interconnection assets at some connection nodes as well as at interconnection nodes). Hence, the set of core grid assets and the set of interconnection assets will inevitably differ.

7.2 Definition of connection and interconnection assets

Some submissions suggested an alternative method of defining connection assets by identifying assets that would not be required in the absence of the connected customer(s) – i.e. a "deprival" method. Examples given where it was suggested that a "deprival" method would be superior to the "augmented loop path method" were Motunui (MNI) and Tiwai (TWI), where the customers are connected to the remainder of the grid at two locations, creating a loop.

Such an alternative was considered previously by Transpower³. The "avoided assets" method considered by Transpower in 2005 showed that it would be difficult to apply the method consistently and that discretion would be required to determine which assets could be removed if a node were removed, and hence which nodes and links would be connection nodes and links. For example, if MNI were removed, the links connecting it to Carrington Street (CST), Huirangi (HUI) and Stratford (SFD) could be removed, so MNI-CST, MNI-HUI and MNI-SFD would be considered connection links attributable to the MNI connection node, and CST would be an interconnection node. If, however, removal of the CST node were considered, the links CST-SFD, CST-MNI and CST-HUI would be categorised as connection links, and MNI would be an interconnection node.

A similar situation occurs with TWI. The example given considers removal of TWI, but if Invercargill (INV) were to be removed instead, TWI would clearly be an interconnection node. This situation can arise wherever there is a loop – if the node(s) being considered for removal is(are) located on one leg of the loop and categorised as connection, the node(s) on the other leg of the loop will be interconnection (and vice versa).

This method was therefore not considered further in the *Transmission Pricing Methodology Supplementary Material*, June 2006, which aimed specifically at meeting the requirements set out by the Commission in the *Statement of Reasons*⁴. Transpower concluded⁵ that the "augmented loop path" method best met those requirements and reduced the amount of discretion needed to be exercised by Transpower when determining which part of a loop should be categorised as connection and which part should be interconnection.

In Transpower's submission on the Commission's consultation paper, it was noted that there are limited circumstances where a "deprival" approach is unavoidable and some discretion must be exercised. When grouping assets into a node, a "deprival" or "avoided assets" approach is needed to determine whether the location at which a circuit deviates (from a location on an interconnection link to a connection node) should be classified as a separate node⁶.

³ Section 2.1.3, *Transmission Pricing Methodology Supplementary Material*, Transpower, May 2005

⁴ Paragraph 100, The Commission's Statement of Reasons in relation to the Proposed Guidelines for Transpower's Pricing Methodology, Electricity Commission, 18 February 2005

⁵ Section 2.2.2, *Transmission Pricing Methodology Supplementary Material*, Transpower, June 2006

⁶ Answer to Question 9 Submission to the Electricity Commission on the Transmission Pricing Methodology Consultation Paper, Transpower, February 2007

7.3 Allocation of shared connection assets

Some submissions suggested different methods of allocating the connection charges between customers using shared connection assets. One such suggestion was that the same number of highest peaks be used for offtake and injection. In the proposed TPM, the twelve highest offtake peaks are used to calculate Anytime Maximum Demand (AMD) while a single peak is used to calculate Anytime Maximum Injection (AMI). This is the same as the current method and Transpower saw no reason to change it as explained in the *Supplementary Material*⁷.

It has also been suggested that the allocation of charges for shared connection asset be decided by voluntary agreement between the customers, with the allocation method in the TPM serving as a default allocation. Transpower does not consider that the TPM should be a default method for the reasons set out in its substantive submission. Transpower should calculate and invoice customers on the basis of the TPM, as it is obliged to do so under the Electricity Governance Rules, and customers may enter into voluntary agreements outside the TPM, if they so wish. Such voluntary arrangements would not form part of the TPM, nor would they involve Transpower (or the Commission). The inclusion of voluntary agreements in the TPM would cause unnecessary complications once the TPM is incorporated into Part F of the Electricity Governance Rules, as any change to such a voluntary agreement would presumably require the process contained in rule 8 of section IV of Part F to be followed.

7.4 "But for" alternative

A "but for" alternative for defining connection assets was proposed in a submission prepared by the New Zealand Institute of Economic Research (NZIER) for the Major Electricity Users' Group (MEUG). The NZIER/MEUG proposal goes beyond the "deprival" method referred to earlier and proposes that new investment in grid capacity also be considered as deep connection so that, over time, there would be fewer interconnection assets (and more connection assets).

The NZIER/MEUG proposal claims that the "but for" approach has been successfully used by the PJM Interconnection (Pennsylvania-New Jersey-Maryland) to provide for participant funding of new transmission investment. The "but for" approach requires the establishment of a baseline, from which incremental investment can be calculated and responsible parties identified and charged. Such an approach may be a more rigorous interpretation of "causer pays", but it is not without problems. The problems with this approach include:

- determining the baseline, from which incremental causer-specific investments are then determined;
- the lumpiness and economies of scale of new transmission investment; and
- where there are multiple causers e.g. new generation in one region and increased load in another – determining the allocation of costs between them.

Previous efforts by Transpower to introduce participant funding of new transmission investment through multi-party new investment contracts were unsuccessful and it would take considerable time to design and implement such a development under the Electricity Governance Rules (if the Commission were to decide to consider such a method further).

The following comment in the *Ten-Year Plan (2006 – 2015)* of *Electric Companies in Maryland* is pertinent in this context:

"PJM through one of its working groups is reviewing existing transmission cost allocation methods to determine whether they should be changed. Reviewing cost allocation tariffs is in part driven by transmission projects becoming larger, with the result that reliability and economic benefits are more regional in nature. Consistent with this development a FERC administrative law judge recently recommended that the costs of all existing transmission facilities in PJM be allocated evenly across the system

⁷ Section 2.5.1 *Transmission Pricing Methodology Supplementary Material*, Transpower, June 2006

(a tariff arrangement called "postage stamp"), since all members of PJM benefit from the existing infrastructure."⁸

It would therefore appear that the future life of the "but for" method in the PJM Interconnection may be limited.

Applying the "but for" approach to new investment in grid capacity would be contrary to the existing guidelines. Recovering the costs of new interconnection assets by re-defining them as deep connection assets would be contrary to guideline 12, which requires that charges for existing <u>and new</u> interconnection assets be on a postage stamp basis. The NZIER/MEUG proposal seeks to circumvent guideline 12 by treating all new transmission investment as connection, but this would be contrary to the intention⁹ of guideline 10, that the costs of connection assets be recovered from those connected to them.

7.5 Total connection charges

One submission queried why the proposed TPM produces lower total connection charges than the existing TPM, when the connection definition is significantly deeper. This is because, under the proposed TPM, the asset return rate is determined using the regulatory asset value of connection assets only, whereas the existing TPM calculates the asset return rate based on the regulatory asset value of all AC assets. Using the regulatory asset value of connection assets only produces a lower asset return rate, because the average age of connection assets is greater than the average age of all AC assets. This change was made to remove an element of cost sharing between connection and interconnection assets, which is present in the current methodology, and to link the costs of providing connection assets more directly to the users of those assets. The proposed method is more consistent with guidelines 9 and 10 and the pricing principles in rules 2.1 and 2.4. This was explained in section 2.4.1 of the *Transmission Pricing Methodology Supplementary Material*, June 2006.

8. HVDC Charges

8.1 Allocation between offtake and injection customers

A number of submissions proposed revisiting the HVDC charge allocation. Some submissions suggested reallocating the HVDC link 50:50 between South Island generating stations and offtake customers (and that the offtake customers' allocation be recovered through the interconnection charges).

The Commission has undertaken extensive consultation on this matter and has reached a decision, which it has explained at length. Guideline 15 is quite clear that the costs of the HVDC link and any replacement or upgrade to it are to be charged to all South Island generating stations that inject into the grid.

8.2 Allocation between South Island generators

In the proposed TPM, HAMI is the single highest peak occurring over the most recent and preceding four capacity measurement periods. It has been suggested that:

- HAMI be determined over only the most recent capacity measurement period;
- the number of highest injections used to calculate HAMI should be increased from 1 (to 100 or, in one submission, to 17,520); and
- HAMI should be adjusted when a generating station is de-rated.

⁸ *Ten-Year Plan (2006-2015) of Electric Companies in Maryland,* Public Service Commission of Maryland, prepared for the Maryland Department of Natural Resources, December 2006, p39

⁹ Transpower's interpretation of the intention of guideline 10 is that connection assets are those assets used to connect a customer to the grid, not <u>all</u> the grid assets to which the customer is connected.

Transpower has previously found that, for grid-connected generators, changing the number of highest peaks (from 1 to 12 or 100) has relatively little impact on their HAMI. However, increasing the number of highest peaks beyond 12 can significantly reduce the HAMI for some embedded generators¹⁰. Since HAMI is intended to approximate the maximum injection capacity of both grid-connected and embedded generators, Transpower does not consider that the number of highest peaks should be greater than 12. The use of HAMI better approximates the maximum injection capacity of grid-connected generators than AMI (which is calculated over the most recent capacity measurement period only).

In the event that a grid-connected generating station's capacity is permanently de-rated, Transpower considers that a mechanism should be available to adjust its HAMI, but notes that such adjustments could be made by way of the adjustment provisions in section 7.1 of the TPM.

9. Assets subject to new investment agreements

Contrary to statements in some submissions, it is clear from sections 4.25 to 4.27 of the TPM that a return on assets that are subject to new investment agreements is not recovered under the TPM.

10. Interconnection charges

10.1 Definition of regions

Transpower agrees with other submitters that the number of regions defined in the proposed TPM is the minimum number that provides a (slightly) greater incentive to manage load in regions requiring major new transmission investment relative to the regions that do not. Some submitters have suggested that the definition of regions could (or should) be more complex and detailed, and that there should be more than four regions.

Transpower does not consider that a more complex and detailed definition of regions is warranted at this stage given the limited scope for differentiating charges between regions under guideline 12. Transpower has previously considered 13 regions to which regional coincident peak demand (RCPD) charging could be applied¹¹. Transpower concluded that defining the regions at such a detailed level would be a lengthy process in itself because:

- there are no clear-cut geographical boundaries for defining a large number of regions; and
- there are strong incentives for customers to define regions in a way that minimises their interconnection charges – i.e. so that their grid exit points are located in a region (or over several regions) with peak demands occurring at times other than their own peak demand times.

These regional boundary issues, while not necessarily insurmountable, would take considerable time to resolve.

A further suggestion was that the regions should be defined as each distribution company's geographical area. This would enable each distribution company to manage its aggregate anytime load. However, this concept would not provide incentives to manage regional peak demands and would also mean that the interconnection charges of grid-connected large industrial customers would remain on an AMD basis. One of the aims of moving to a RCPD method is to provide customers, including large industrial customers, with incentives to manage their loads at regional peak times, rather than anytime.

¹⁰ Section 4.2 *Transmission Pricing Methodology Supplementary Material*, Transpower, June 2006

¹¹ Section 4.3.3 Transmission Pricing Methodology Supplementary Material, Transpower, May 2005

10.2 RCPD measurement for small regional loops

It was suggested that the offtake and/or injection, where both are present in a small regional loop, should, for the purposes of determining the RCPD for calculating interconnection charges, be measured (or calculated) at the point at which the single link connects the small regional loop to the remainder of the grid. This would put offtake and injection customers connected to a small regional loop on the same footing as those with embedded generation (or notionally embedded generation).

As this suggestion seems reasonable, the Commission may wish to consider it as a minor modification to the proposed TPM.

10.3 Values of "N"

Views in submissions on the values of N used to calculate the RCPDs included:

- N should be less than 12 for all regions to provide stronger load management incentives;
- N = 12 is excessively harsh and should be larger;
- N should not be fixed at all but should be allowed to change to provide dynamic signalling;
- N should be the same for all regions;
- N should be 100 for unconstrained regions, but adjusted for constrained regions. It should be reduced according to the number of years before augmentation is needed.

The N values in the proposed TPM are based on the current TPM (N = 12) for the Upper North Island (UNI) and Upper South Island (USI) regions to maintain current load management incentives (but shifted from anytime to regional coincident peak times), and an increase in N to 100 for Lower North Island (LNI) and Lower South Island (LSI) regions to reduce load management incentives (because load management in these regions would not alleviate transmission constraints and could, in fact, exacerbate them).

It is clear that there is no consensus among submitters as to the most appropriate values of N and Transpower considers that it would be difficult (if not impossible) to calculate optimal values of N reliably based on observed customer responses to the interconnection charges.

10.4 Capacity measurement period

There has been some misunderstanding of the role of the capacity measurement period¹². The capacity measurement period is the period used to calculate the interconnection <u>rate</u> (in /kW). It has been confused with the period used to calculate the interconnection <u>charges</u>.

The capacity measurement period is a period prior to the start of the pricing year which enables Transpower to set and advise customers of the interconnection rate for the coming pricing year. If the capacity measurement period were to change during the pricing year – e.g. if it were to move forward on a 12-month rolling basis – the interconnection rate could change at any time during the pricing year, creating uncertainty and providing confusing and meaningless price signals. The interconnection rate and all customers' interconnection charges would change each time there was a change in any of the regional peak demands.

Alternatively the capacity measurement period (and the interconnection rate) could be fixed at the start of the pricing year and the period over which the RCPDs are measured for calculating the interconnection charges rolled forward on a 12-monthly basis. This would be

¹² An exception was the submission from Orion, which suggested that the period over which the regional coincident peak demands are measured for calculating the interconnection charges be defined as the "peak measurement period" (and that the period should be set at 1 November to 31 October prior to the commencement of the pricing year). This would avoid confusion between the two periods, even if both are set to cover the same months.

analogous to the current TPM (but using RCPD instead of AMD). It would, however, mean that, although the interconnection rate would remain the same for the entire pricing year, there would be changes to a customer's interconnection charge whenever there was a new regional peak demand for the customer's region. It would also lead to possible under or over recovery of interconnection charges by Transpower, and the need for future EV adjustments.

Under the proposed TPM, the capacity measurement period and the period used to calculate the interconnection charges will be the same. This will maximise certainty for customers and remove a complication which can lead to over or under recovery of Transpower's economic costs.

10.5 Provision of real-time regional demand data and regional load co-ordination

A large number of submitters suggested that real-time regional demand data should be provided to enable customers to respond more effectively to the interconnection charge price signals. The appropriate method of providing this information, which will be useful to customers, should be addressed by the Electricity Commission. A possible approach would be for the Commission to contract with EMS to provide this information and supply it to the industry.

A related issue raised by submitters was the establishment of a regional co-ordinator to assist customers within a region to manage regional demand. Transpower believes that it should be left to customers to organise regional load co-ordination on a voluntary basis, wherever customers consider that this would be beneficial to them.

10.6 Ineffectiveness of pricing signals

A number of submitters have noted that the effectiveness of the pricing signals provided by coincident peak charging is likely to be limited for a number of practical reasons. One submitter (WEL Networks) was also under the impression that the proposed method "was in Transpower's interests".

Transpower agrees that the pricing signals from a coincident peak charging method are likely to be attenuated, and made the following observations in the June 2006 *Transmission Pricing Methodology Supplementary Material*:

"It should be noted that the effectiveness of any coincident peak demand pricing signal will be attenuated by at least the following factors:

- relatively few customers will see the signal directly;
- the signal is bound to be modified considerably as it is passed through from distributors to retailers and final customers;
- the total price impact will be relatively small compared to the total magnitude of energy prices and variations in those prices;
- customers wishing to avoid the peak charging periods will need to weigh the risk that they might not choose the correct periods to reduce consumption; and
- reducing consumption during some periods will result in loss of output and revenue for commercial customers, which they will have to weigh against the possible commercial benefit of reduced interconnection charges."

The proposed TPM has been developed by Transpower to meet the Commission's requirements, including the requirement expressed in the following public statement made by the then Chair of the Commission at the February 2006 HVDC Pricing Guidelines Conference:

"...this Commission will continue to reject a pricing methodology that continues to have anytime maximum demand as its principal mechanism of pricing transmission and that we will continue to want to see something along the lines of a system coincident peak demand pricing mechanism. I just want that to be clear. I think this Commission has been unanimous and quite consistent on that."¹³

Given this clear indication that the Commission expected the proposed TPM to include a coincident peak allocation method for the interconnection charge (and that it would reject an anytime maximum demand method), Transpower has aimed to develop a coincident peak method which minimises the negative features of such methods.

10.7 Mechanisms for changing regional boundaries and "N" values

A number of submitters suggested that there should be mechanisms in the TPM for changing the regions and the N values for each region. Transpower notes the wide range of submitters' views on how the regions should be defined and the values of N for each region, and considers that it would be difficult to develop a set of objective rules within the TPM that could be applied to automatically update the regions and their associated values of N as circumstances changed. The TPM would have to specify all the possible changes in circumstances and set out the changes to the methodology in the event that any one or more of those changes in circumstances were to occur.

Updating the definitions of regions and their associated values of N would be a major task that would arise only if there were material changes to the grid and/or grid upgrade plans. Transpower considers that the proposed mechanism is unnecessary as Rule 11.2 of section IV of Part F of the EGRs already enables the Commission to initiate a review of the TPM where there has been a material change in circumstances.

Transpower believes that relying on the review provisions in Rule 11.2 of section IV of Part F of the EGRs will provide additional certainty for transmission customers over the medium term. If provisions to enable regions to be varied were contained in the TPM, this would add to the risks faced by customers and increase the likelihood that variations would be proposed whenever individual customers considered that a commercial advantage to them might accrue from a regional boundary change.

10.8 Strata alternative

An alternative method of calculating interconnection charges ("Strata alternative")¹⁴ was proposed by Strata Energy Consulting in a submission prepared for Rio Tinto Aluminium New Zealand (RTA).

One of the consequences of moving from an AMD method of allocating interconnection charges to an RCPD method¹⁵ is that regions with less diverse loads will pay a greater proportion of interconnection charges. Another consequence is that, where a customer's load is a substantial proportion of the regional load, that customer will pay a greater proportion of the interconnection charges.

RTA is a baseload user and RTA's load is a substantial proportion of the LSI regional load. Thus, the LSI's total interconnection charges increase under the RCPD method in the proposed TPM, relative to the AMD method in the current TPM, and RTA's interconnection

 ¹³ Transcript of HVDC Transmission Pricing Methodology Conference, Electricity Commission, 24 February 2006, p80, lines 23-30
¹⁴ Transmission Pricing Methodology Conference, Electricity Commission, 24 February 2006, p80, lines 23-30

¹⁴ Transmission Pricing Methodology – A review of Transpower's proposal to the Electricity Commission, Strata Energy Consulting, February 2007

¹⁵ It should be noted that this shift in interconnection charges is due to the move from an AMD to a RCPD method of allocation and not to the different N values for the regions, which have only a small impact.

charge increases because it makes up a large part of the LSI load. The Strata alternative prevents increases in the LSI and RTA interconnection charges by:

- fixing the relative amounts of interconnection revenue charged to the regions at their current levels; and
- allocating the interconnection charges within the LSI region (and the LNI region) using the AMD method.

The Strata alternative would provide greater price stability than the proposed RCPD method by preserving the allocations produced by the AMD method. However, the Strata report does not provide any argument to support the view that the AMD method produces a more appropriate allocation of interconnection charges between regions. It could, for example, be argued that the AMD method allocates too high a proportion of charges to regions with diverse loads.

10.9 Other approaches to the interconnection charge (including LRMC pricing)

A number of submitters have discussed alternative approaches to the "postage stamp" interconnection charge. The Commission consulted and decided on this matter in 2004, when it developed the first set of guidelines. (Since then, only the guidelines relating to the HVDC charges have been substantially amended.) It is not possible to revisit the Commission's decisions on the interconnection charges at this stage in the process.

The Commission's decision in response to the September 2004 consultation document *Proposed Guidelines for Transpower's Pricing Methodology* was that the interconnection charge should be "postage stamp" in character. The alternative of locational pricing was rejected, although the Commission indicated that it wished to undertake further work on locational pricing options in the future. This decision was qualified by the requirement that Transpower should consider "anytime versus regional or national coincident peaks" as allocative bases for the postage stamp charge (guideline 13).

In its 18 February 2005 document *The Commission's Statement of Reasons in relation to the Proposed Guidelines for Transpower's Pricing Methodology*, the Commission made the following observations about LRMC pricing:

"Determining LRMC is complicated for grid investment because it varies at each grid exit point (GXP) and depends on a single view of the future pattern of generation and load. Moreover, LRMC charges reflect regulatory decisions rather than market forces, and therefore carry significant risk for investors relying on the LRMC signal." (para. 65)

"Location charges that seek to recover the cost of new investments from only a few sources of load growth, or from only a few sources of new generation, will provide location and demand management signals that are too strong. The charge to each customer for new investment as a proportion of the investment cost should not exceed the proportion of the new capacity used by the customer." (para. 66)¹⁶

11. Prudent discount policy

The main concerns expressed in submissions concerning the proposed prudent discount policy are:

- prudent discounts might be used instead of (connection) asset optimisation where a customer is able to construct a by-pass;
- prudent discounts might be used to discourage embedded generation;
- prudent discounts might be used to discourage economic bypass proposals;
- the cost of prudent discounts will be recovered through the interconnection charges.

 $^{^{\}rm 16}$ The "but for" approach in the NZIER/MEUG proposal would have similar issues

Existing connection assets have been valued taking into account lower cost alternatives through the ODV process. Future connection assets will be provided either under a New Investment Contract (NIC) or following their inclusion in an approved Grid Upgrade Plan (GUP). In the case of a NIC, a customer will be contracted to pay the associated charges and a prudent discount will not apply. Where connection assets have been provided under an approved GUP, Transpower expects to recover the full economic costs of the assets. In this case, if a prudent discount becomes necessary, Transpower considers that the cost of the prudent discount should be recoverable through the interconnection charges. However, whether or not this will be permitted is a revenue setting matter under the jurisdiction of the Commerce Commission and outside the scope of the TPM.

The transparency of the prudent discount process, including the ability to refer all decisions for review by an independent expert, will ensure that the prudent discount policy is not used to prevent economic by-pass of the grid by customers wishing to build new lines or modify their distribution networks. Where assets have previously been optimised, these optimisations will be preserved by the use of the replacement cost adjustment factor (see the definition of "replacement cost" in the proposed TPM). It is also expected that, as part of the move to an historical cost based valuation method, Transpower's initial system fixed asset valuation under the new method will be equal to the last ODV valuation. However, this is a revenue setting matter that is outside the scope of the TPM.

Transpower does not intend to provide prudent discounts in response to embedded generation proposals. Such prudent discounts would, as several submitters have pointed out, have the effect of discouraging embedded generation.

The evaluation provisions in the proposed TPM that determine whether or not a prudent discount will be granted specifically prevent prudent discounts from being granted when the alternative project is economic. Hence, discounts cannot be granted to discourage economic alternatives. It is only where an alternative is uneconomic but nevertheless commercially attractive to a particular customer or customers that a discount may be granted.

The most common form of prudent discount currently, and most likely in the future, is that for notionally embedded generation. Prudent discounts are provided so that grid-connected generation located close to a load does not have to embed physically to receive the benefits of offsetting generation against load. The prudent discount is provided through a revised method of calculating the load, which is measured net of generation. Using the net load to calculate the interconnection charge (and interconnection rate) means that the cost of the prudent discount is automatically recovered through the interconnection charges. The interconnection rate determined in this way is the same as the rate would be if the notionally embedded generation had been physically embedded.

A submission from Todd Energy claimed that the prudent discount policy, while encouraging embedded generation, discriminates against distributed generation – i.e. grid-connected generation located close to a load. This is not the intention, as the provision of prudent discounts for notional embedding clearly shows. The problem appears to be that distributed generation that is able to be notionally embedded may be unable to capture the benefits of the lower interconnection charges. If this is the problem, it is a matter that needs to be resolved between the distributed generator and the load customer.

12. Transitional arrangements

Some submitters suggested that there should be transitional arrangements to enable customers to adjust to the TPM, since the capacity measurement period for a 1 April 2008 introduction of the TPM is already under way. Transpower, and other submitters, do not consider transitional arrangements to be necessary. Although the TPM has yet to be finalised, the main elements and, in particular, the main change to an RCPD method for allocating interconnection charges, have been known for some time.