Transmission Pricing Advisory Group

Transmission pricing options

For discussion with TPAG

9 February 2011

Note: This paper has been prepared to provide background to TPAG on transmission pricing options considered by the transmission pricing review. Content should not be interpreted as representing the views or policy of the Electricity Authority.

Transmission Pricing Advisory Group

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1 1. Introduction

1.1 Purpose

1.1.1 This paper has been prepared by the Authority to provide the Transmission Pricing Advisory Group (TPAG) with a high-level overview of the transmission pricing options considered by the transmission pricing review.

1.1.2 This paper should be read in conjunction with other papers provided to TPAG in particular:

(a) the roadmap paper which provide context and an overview of the transmission review process. It also provides a guide to the documents published as part of the review or by stakeholder groups; and

(b) the draft high level analysis framework that is intended to assist TPAG in evaluating options for Transmission Pricing Methodology (TPM) and determining a preferred option for articulation in a discussion paper to be released in late March 2011.

1.1.3 The Stage I and II consultation papers set out the Electricity Commission's (Commission's) considerations of the options.

1.2 Structure of the paper

1.2.1 The remainder of this paper considers the following groups of options:

(a) The stage I high-level options

(b) HVDC options

(c) Options for deferring reliability investment

(d) Other options

1.2.2 Figure 1 below illustrates the grouping of the options.

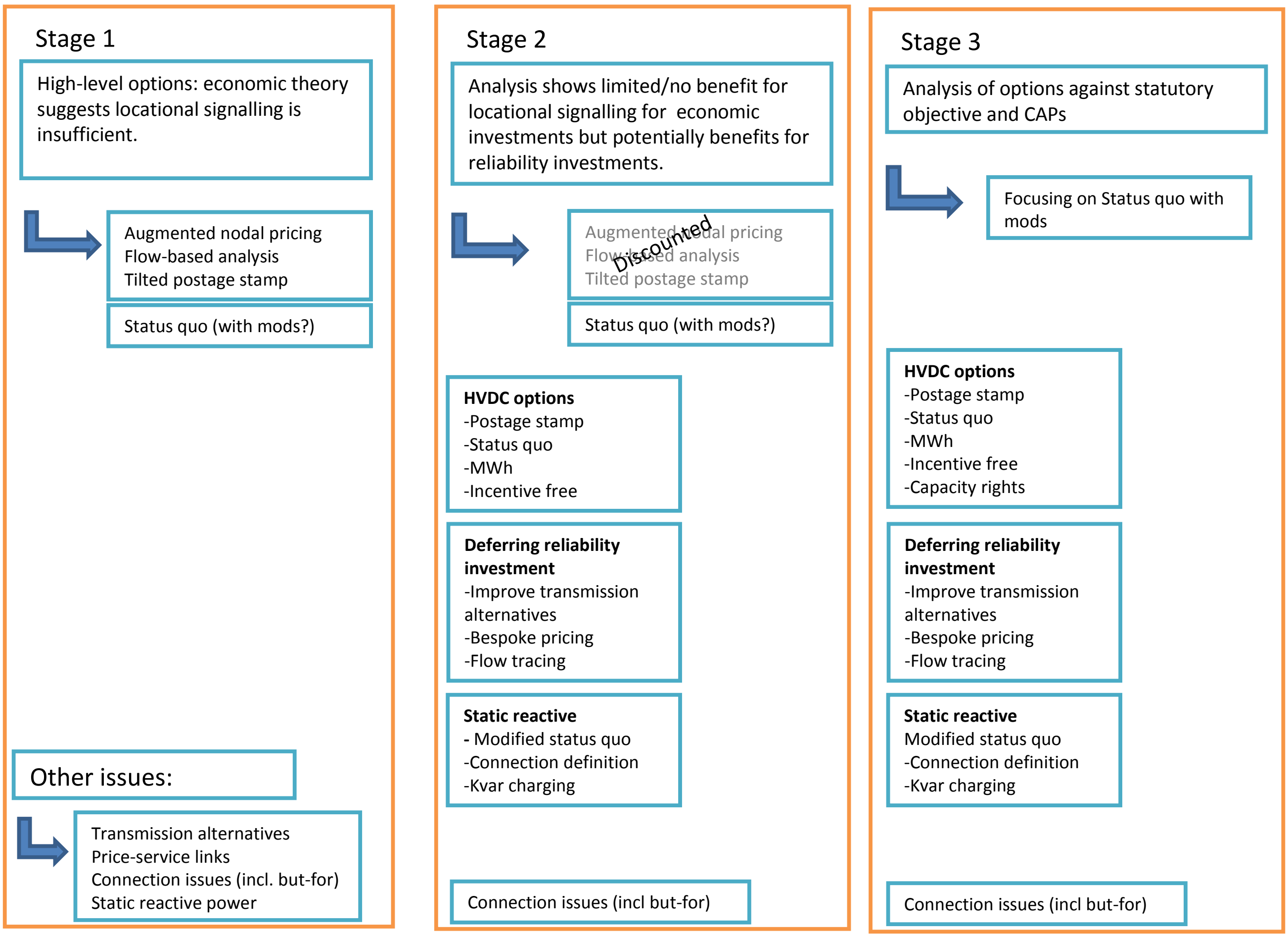

Figure 1 Overview of options

2 Stage I high-level options

2.1 Background to the stage I high-level options

2.1.1 Stage 1 considered issues with the current transmission pricing, economic theory and international experience. In order to distinguish high-level option issues from more detailed considerations, the focus of stage 1 was economic theory considerations in particular whether there was sufficient justification to consider enhanced locational signalling in addition to that provided by nodal pricing, deep connection and the grid investment test.

2.1.2 Nodal pricing, the connection charging regime and the grid investment process already provide some locational signalling, but the economic theory investigated in stage 1 suggested that this was likely to be insufficient (in a true economic sense) due a trio of factors: the use of deterministic reliability criteria in transmission investment approvals, economies of scale and timing considerations in transmission investment, and the inaccurate pricing of supply security (i.e. the absence of nodal scarcity pricing).

2.1.3 Stage 1 identified three alternatives to the status quo transmission arrangements that might provide enhanced locational signalling. These three were considered alongside the status quo. These are described below.

2.1.4 Stage 1 also considered four issues that had been raised with the current regime: the lack of a link between price and service, issues with connection arrangements, transmission alternative arrangements and static reactive compensation. These issues are not considered here as they did not contribute to the development of the initial high-level options. Their consideration contributed to the development of some of the options described in section 4 and 5.

2.2 Status quo arrangements

2.2.1 The current transmission pricing methodology (TPM) comprises:

- A connection charge that recovers the costs of dedicated and spur-line assets connecting participants to the interconnected grid.
- An interconnection charge imposed on load that is the function of both a postage-stamped interconnection rate and the customer's contribution to the regional coincident peak demand (RCPD).
- A postage stamp charge on South Island generators charged on historical peaks to recover the costs of the existing HVDC link and any augmentations to it.

2.2.2 The Stage I consultation paper asked submitters whether their might be relatively minor modifications that could be made to the existing TPM to enable it to provide appropriate locational signals.

2.3 Tilted postage stamp approaches

2.3.1 Under this approach, charges are postage stamped, but are higher for loads in predominantly importing regions and lower for loads in predominantly exporting regions. If future load growth in New Zealand follows historical trends, this should lead to higher charges for loads in the North Island than loads in the South Island. If this charging method were to be applied to generators, it would apply in an inverse manner; generators in the South would face higher charges than those in the North. A number of methods of applying a tilted postage stamp approach have been suggested from charging based on latitude, or based on the grouping of participants' grid exit points within geographic zones. This approach was considered by NERA in its work for the CEOs' Forum[1]. NERA considered that tilted postage stamp approaches could involve a few zones or possibly a more granulated approach.

2.4 Augmented nodal pricing

2.4.1 This approach seeks to directly address the deficiencies in nodal energy pricing. It is based on an assumption that the current regime results in excessive or premature network investment, and that it is possible to identify those generators and loads that benefit most from this investment. Under this approach, transmission charges would be highest for those that benefit most from this investment, and lowest or even negative for those that are made worse off as measured by market prices. The application of this approach depends on being able to identify transmission investment that is in excess of purely economic investment, and also further identifying which parties benefit and which parties lose out as a result of any excessive investment.

2.5 Load flow-based approaches

2.5.1 Load-flow based transmission pricing options involve a process of network analysis to attribute costs to participants based on identifying the network assets they use. These approaches can be based on flows on the existing network as in Australia where a method called Cost Reflective Network Pricing is used.

1 Available at http://www.ea.govt.nz/document/6616/download/our-work/programmes/priority-projects/transmission-pricing-review/

They can also use forward-looking network analysis and costs as in the UK where 'Investment Cost Related Pricing' is used. A load-flow-based approach has previously been used in New Zealand but was replaced owing to concerns over complexity and excessive variability of transmission prices.

2.6 The Commission analysis on the stage I high-level options

2.6.1 The purpose of stage II was to support the Commission's decision-making as it narrowed down the possible options for a transmission pricing methodology. Following stage I and considering the views of submitters, the Commission concluded in stage II that given the factors mentioned earlier in paragraph 2.1.2, it is unlikely that - theoretically - nodal pricing will always provide adequate signals for efficient generation and load investment. Stage II analysis then considered whether there would be benefits in practice in implementing a new TPM with enhanced locational signalling.

2.6.2 The Commission undertook substantial analysis to estimate the potential upper bound of economic benefits from providing further locational signals through the TPM. This was done by modelling the difference between two alternative scenarios where:

- Transmission interconnection costs are not considered when generation investments are made; and
- Generation and transmission investment are perfectly co-optimised ie all transmission investment costs are considered in making decisions to invest in generation and the least cost expansion to meet demand is selected (this is a proxy for an 'ideal' locational signal).

2.6.3 The Commission's used the Generation Expansion Model (GEM) to derive an estimate of overall system costs for the different scenarios[2]. The Commission's analysis suggests that the upper bound of benefits of implementing locational signals through the TPM to signal to generation the cost of economic transmission investment[3] appears to be immaterial. Further, it is possible that a transmission pricing regime, if not precise enough, could lead to unintended inefficiencies by over-signalling locational costs and induce poor investment decisions around the type, timing and location of generation.

2.6.4 The Commission's position set out in the stage II consultation paper was that there was no justification to progress further work in developing augmented nodal pricing, load flow-based approaches or tilted postage stamp as the basis for any future TPM to avoid economic transmission investments. This position was based on the lack of material benefits from locational signalling for economic transmission investments, and the likely complexity associated with each of the high-level options intended to enhance locational signalling.

2.6.5 The Commission's preference, expressed in the stage II consultation paper, was for a TPM based on the status quo. It suggested some modifications to the status quo where benefits could be demonstrated including:

(a) Options for the HVDC charging regime

(b) Options for deferring reliability transmission investments

(c) Other modifications such as changes to the static reactive compensation arrangements and connection arrangements

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[2] An appendix to the stage II consultation paper describes the analysis: http://www.ea.govt.nz/document/9995/download/our-work/consultations/transmission/tpr-stage2options/

[3] Economic transmission investments are those investments that reduce system costs as opposed to reliability transmission investments that are required to meet demand.

2.6.6 Although the focus of the TPAG analysis and assessment of options should be on the modifications to the status quo, it is necessary to meet the TPAG terms of reference by undertaking and summarising an assessment of the high level options outlined in the stage 1 options paper. This could be undertaken through a combination of qualitative and quantitative assessments based on existing work.

2.6.7 The objective is to solidify the understanding of the GEM "co-optimisation" analysis in particular (because it is a significant factor in eliminating some of the high level options) and to ensure that there is general support for eliminating the TPS, ANP and LFB based approaches to recover all transmission costs from load and generation.

3 Options for the HVDC charging regime

3.1 Background to the HVDC options

3.1.1 The Commission's stage II analysis on the benefits of locational signalling concluded that there was no material value in providing for an enhanced locational signal to generators through the interconnection charge. There is currently no locational transmission pricing signal for AC interconnection assets for generators. The situation is different for HVDC assets.

3.1.2 The current HVDC charge is levied on all South Island generators that inject into the Grid (including new generators). As such, it provides a locational signal to invest in generation in the North Island in preference to the South Island.

3.1.3 The stage 2 consultation paper presented an analysis showing the costs and benefits of the current design of the HVDC charge (relative to a regime with no charges on SI generators and no incentive effects). This analysis suggested that there may be material benefits in alternative HVDC charging regimes. The stage II paper suggested three options alongside the status quo, and also considered market-based alternatives suggested by NZIER. These options are described below:

3.2 The status quo

3.2.1 Under the current transmission pricing arrangements the HVDC costs are met through a charge on South Island generation plan with charges based on Historical Anytime Maximum Injection (HAMI) into the grid at the customer's location ie a charge on historical peak injection. Charges are not levied on generation embedded in a lines network.

3.3 MWh charge

3.3.1 Under this option, the HVDC charge would remain on South Island generators but would be allocated proportionately to generation in MWh. The effect of changing to a per-MWh charge would be to avoid penalising peak injections and hence avoid discouraging investment in peak generation or generators operating to their peak capacity. Any per-MWh allocation should be based on total generation over several years – as opposed to generation in the current year only, which would cause substantial year-on-year variation. Some submitters to the stage II consultation paper suggested a variant of this charging regime, with the MWh charge levied on both North and South Island generators depending on the direction of flow on the HVDC link. Other submitters suggested that the MWh charge could be levied on a mixture of load and generation, again depending on the direction of flow on the HVDC link.

3.4 Incentive-free allocation to South Island generators

3.4.1 Under this option, the HVDC charge would remain on South Island generation plant, but in an 'incentive-free way' that does not distort operational or investment decisions. Generation assets in existence at 'X' date would cover the costs of the HVDC charge. Both NERA and the Commission considered an incentive-free approach, but noted practical issues.

3.5 Postage stamp

3.5.1 Under this option HVDC costs would be spread broadly throughout New Zealand over load, in the same manner as interconnection assets are charged currently. Alternatively the charge could be shared with generation.

3.6 HVDC capacity rights

3.6.1 NZIER proposed alternative options for the HVDC charge, initially in response to NERA's work with the CEOs' Forum, but also as part of submissions to both the stage I and stage II consultations. NZIER suggested two market-based approaches to charging for the HVDC, one involved an arbitrageur approach and capacity rights approach. Only the capacity rights option is included here because the arbitrageur approach would be outside of the scope of the transmission pricing review and the Authority's responsibility requiring an asset sale or Transpower's involvement in the energy market.

3.6.2 The basic principle of the capacity rights approach is that generators would need to purchase capacity rights in order to use the HVDC link. The approach, as described at a high-level by NZIER, would involve introducing three new trading processes:

(a) an annual allocation of capacity rights at Transpower's unit cost based on historical usage;

(b) a secondary trading market for capacity rights that would operate up to the start of the half-hour to which a capacity right relates; and

(c) spot trading of capacity rights which would operate in conjunction with the offering of generation for dispatch.

3.6.3 The Commission considered that in its stage II consultation paper that the capacity rights approach should not be progressed further. This was due to the lack of benefit in radically changing charging arrangements to provide locational signals to defer or avoid further HVDC investment that is unlikely to be required. Although the Authority continues to have concerns about the capacity rights approach it has further considered whether the design of a possible capacity rights option could be improved and considered alongside the other HVDC options, and proposes that it be included in the TPAG assessment.

4 Options to defer reliability investments

4.1 Background to the options to defer reliability investments

4.1.1 Reliability investment is primarily to support reliable supply to load. The need for such investment tends to be driven by peak demand. Avoiding or deferring the costs of reliability-driven investments typically involves investment in alternatives – namely demand-side management and firm local plant able to generate at peak times. Avoiding or deferring investment in reliability transmission assets should be encouraged where it is economic to do so. The stage II consultation paper considered the possible benefits from providing further signalling or other mechanisms for deferring reliability investments.

4.1.2 In summary, the analysis concluded that there is predicted to be a steady growth in peak demand, with a resulting need for investment in transmission assets, or in alternatives. There could be significant efficiency gains if demand side management or peak generation is located in regions where transmission investment would otherwise be made.

4.1.3 The stage II consultation paper suggested three options for providing mechanisms to defer reliability investments:

4.2 Bespoke pricing

4.2.1 This is an approach that imposes a higher charge on loads and provides a positive credit for peaking generators in particular regions where demand growth is driving the on-going need for reliability investments. This term was used in the NERA report as a tilted postage stamp regime customised for specific regions. Participants in other regions would continue to face the standard interconnection charge that would apply only to loads. In subsequent work for the Commission, Covec[4] has proposed two models of 'bespoke pricing'.

(a) A "specific bespoke" pricing option that is in effect a form of transmission alternatives regime whereby a customised pricing signal could be triggered in a region when a reliability investment is listed in the Grid Reliability Report (GRR).

(b) A "general bespoke" pricing option which involves dividing the grid into regions in which connected entities would receive positive or negative price signals depending on whether their supply of off-take would exacerbate or mitigate the need for reliability investment within their region.

4.2.2 The status quo already provides some customised pricing signals for load via the differentiated RCPD regime.

4.3 Flow-tracing

4.3.1 A flow-tracing approach seeks to allocate a proportion of interconnection assets to specific connected entities based on their use of the transmission grid as determined by applying a flow-based measure of usage. This could involve either deepening the definition of connection, or allocating some portion of the currently postage stamped interconnection costs to individual loads.

4.3.2 Allocating a greater portion of interconnection costs to individual customers should provide a greater incentive for the relevant loads to take action to defer or avoid new transmission investment that is likely to be required to serve their individual requirements. It should also motivate customers to scrutinise transmission investments more closely.

4.3.3 Flow tracing is a method which is able to calculate the electrical usage of assets by participants. This is achieved through the calculation of Average Participation (AP) factors, for each individual electrical asset, based on historical data. For transmission pricing, these AP factors are then used to allocate the costs of transmission assets.

4.3.4 The intention would be to allocate only a portion of the interconnection assets using flow-tracing; the assets that are used by a small number of individual customers. The costs related to the unallocated interconnection assets would be recovered via postage stamping.

4 Bespoke Pricing Signals; report prepared for Electricity Commission, October 2010.

4.4 Improved transmission alternatives

4.4.1 The possibility of improving the transmission alternatives regime in order to provide a more direct means of procuring generation or demand response to avoid or defer reliability (and/or economic) transmission investment was also considered as an option in stage II. However, the transmission alternatives regime is essentially part of the process that must be applied by Transpower when it is considering transmission investments and applying the Grid Investment Test (GIT). This process is now overseen and regulated by the Commerce Commission, and therefore outside the scope of this work. Nevertheless, it will be important, when developing and evaluating transmission pricing options, that their fit with the transmission alternatives regime be taken into account.

5 Other options

5.1 Introduction

5.1.1 The options described in this section have been considered as part of the' further issues' work which has run through the transmission pricing review to date.

5.2 But-for approach/ deeper investment cost allocation through the Grid investment process

5.2.1 This approach has been put forward in this and earlier reviews by MEUG. The so-called 'but-for' approach is used in PJM essentially as a deep connection charge to large generators and load. The new connections are charged both connection costs and any interconnection augmentations that would not have been needed but for the new connection. In PJM the new connection (generation or load) receives capacity rights in return for its charges. The Commission ruled out this approach owing to its complexity, likely subjectivity and difficulty of implementation (particularly in the NZ where the market model does not include capacity rights).

5.2.2 In its submission to the stage II consultation paper, MEUG continued to favour the but-for approach, and suggested that there may be innovative ways to apply it in NZ. In subsequent discussions with MEUG, MEUG has suggested that its interest in but-for is primarily an interest in allocating costs of new investment to beneficiaries and that it might be feasible to achieve this as part of the Grid investment process rather than a but-for approach.

5.3 Changes to the connection regime

5.3.1 Possible changes to the connection regime have been suggested by parties. They are:

(a) Creating a shallower or deeper definition of connection – this could be through adjusting the boundary definitions in the current TPM, or by applying a flow-tracing approach.

(b) Creating a backstop arrangement for new connections assets where there are practical issues that may hamper mutually-negotiated shared arrangements new connections.

5.4 Static reactive options

5.4.1 The stage II consultation paper outlined three possible options for allocating static reactive power costs. These were:

(a) **Amended status quo**. This would involve amending the current standard in the Connection Code and retaining this as a basis for determining the allocation of costs for static reactive power investments.

(b) **Connection asset definition**. This would involve widening the definition of connection asset to include new static reactive power investments.

(c) **Kvar charge**. This would involve determining an appropriate kvar charge to incentivise more cost-effective investment in static reactive support, either in the transmission network or in the distribution network. Transpower suggested a variation of the kvar charge option in its submission to the stage II consultation paper which involves treating static reactive assets as interconnection assets and charging using reactive draw at peak demand periods.

5.4.2 There is a strong linkage between arrangements to incentivise efficient investment in static reactive compensation and options for deferring reliability investments.

6 Recommendations

6.1.1 It is recommended that TPAG:

(a) Agree that a high level mixed qualitative/quantitative assessment should be applied to narrow down and confirm the elimination of some of the high level options outline in the stage 1 options paper (and summarised in section 2 of this paper);

(b) Agree that a more detailed mixed qualitative/quantitative assessment (based on the evaluation criteria set out in the High Level Analysis Framework Paper) should be applied to the TPM options set out in sections 3, 4 and 5 of this paper.