Alternative Options for Transmission Pricing

Suggestions for the Review by the CEOs' Forum

Report to MEUG

8th October 2009

Preface

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1. Introduction

The Electricity Industry CEOs' Forum has set up a Steering Group to oversee a project on transmission pricing. The purpose of the project is "to determine whether consensus can be achieved on an appropriate and enduring transmission pricing methodology for New Zealand, and if so, what that methodology may be."[1] On the 2nd September 2009 the Steering Group met to consider a report from NERA Economic Consulting.[2] The Report contains three high-level options for reform of transmission pricing. One of the outcomes of the meeting was to invite participants to put forward for consideration alternative high-level options to those identified in the Report. In this paper we provide MEUG with suggestions of alternatives to put forward in response to this invitation.

In the next Section we briefly describe the three options proposed for further consideration by NERA. In Section 3 we discuss in general terms what the objectives for a transmission pricing methodology (TPM) should be in the New Zealand context. What is it that we want the TPM to achieve? From considering why there is a TPM, we also develop an approach to the design that should produce efficient outcomes. In Section 4 we briefly describe various aspects of transmission pricing we believe are worthy of further consideration as components of high-level options. In Section 5, we briefly consider these suggestions relative to the "Transmission Pricing – Project Guiding Principles" and decision criteria the Steering Group agreed late last year. Our recommendations on the additional high-level options that should be considered by NERA and the Working Group conclude the paper.

2. NERA's high-level options

The three high-level options identified by NERA can be described as:

- Tilted postage stamp
- Bespoke tilted postage stamp
- Modified status quo.

2.1 Tilted postage stamp

- Transmission connection assets are paid for on the same basis as under the present TPM, except a shallow definition of what is a connection asset is adopted so that connected parties are only liable for charges relating to the transmission assets directly connected to their own facilities.

[1] NZ Electricity Industry Transmission Pricing Steering Group, *Review of Transmission Pricing Methodology: Terms of Reference*, November 2008. Hereinafter referred to as the Terms of Reference.

[2] NERA Economic Consulting, *New Zealand Transmission Pricing Project: A Report for the New Zealand Electricity Industry Steering Group*, 28th August 2009. Hereinafter referred to as the Report.

- The HVDC charge in the current TPM is discontinued.
- In place of the HVDC charge a new charge for generators throughout the country is applied. This charge is derived using the tilted postage stamp (TPS) methodology.[3] It imposes charges on generators which increase the further "south" they are from Auckland.

  The TPS charge is based on the estimated long-run marginal cost (LRMC) of transmission from a generator of a capacity equivalent to the additional transmission capacity needed in the zone located immediately to its north, which would be avoided throughout the whole transmission network from the implementation of the methodology. From this estimate, the "gap" between the average nodal price in the zone in which the generator is located and Auckland is deducted, as this element of the increased transmission costs for locating further "south" is already provided in wholesale electricity spot prices and it would be inefficient to charge this component twice.

  Table 4 of the NERA report contains some illustrative calculations of the TPS charges that could be imposed on generators in various geographic zones.[4] For the generators in the south of the South Island the charge is significantly less than the LRMC of the HVDC link and its upgrade. Thus, on the basis of this, and that the description in the text is consistent with the derivation in Table 4,[5] the TPS charge would be less than the current HVDC charge and compared with the current methodology the TPS methodology proposed by NERA would shift transmission costs from generators to load. NERA has, however, identified that Table 4 and the description are not accurate and as a result the TPS charge is understated by 50% in Table 4.[6] When the appropriate adjustment is made, generators will in aggregate pay more of the costs of transmission under the TPS methodology than they do under the current methodology.
- Interconnection charges to cover Transpower's revenue requirement not recovered by the shallow connection and TPS charges are paid by load on the same modified postage stamp basis as interconnection charges under the current TPM.

2.2 Bespoke tilted postage stamp

- Connection assets are paid for on the same basis as under the present TPM, except a shallow definition of what is a connection asset is adopted so that connected parties are only liable for charges relating to the transmission assets directly connected to their own facilities.
- The HVDC charge in the current TPM is discontinued.

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[3] For a description of the TPS methodology see NERA, pp. 78 ff. The methodology was proposed in E.G. Read, *Locational Transmission Pricing: A Formulaic Approach*, February 2007.

[4] NERA, p. 88.

[5] NERA, pp. 86-87.

[6] Personal communication from Hayden Greene and Greg Houston.

- In place of the HVDC charge a new charge for generators in some zones throughout the country is applied. This charge is derived using a modified tilted postage stamp (bespoke TPS) methodology and imposes charges on generators in zones where it is desired to discourage their location because of the additional transmission investment that generator investment there will necessitate.
- Interconnection charges to cover Transpower's revenue requirement not recovered by the shallow connection and the bespoke TPS charges are paid by load on the same modified postage stamp basis as interconnection charges under the current TPM.

2.3 Modified status quo

- Connection assets are paid for on the same basis as under the present TPM including the use of the current deep connection definition to define connection assets.
- The HVDC charge in the current TPM is discontinued.
- Interconnection charges to cover Transpower's revenue requirement not recovered by the deep connection charges are paid by load on the same modified postage stamp basis as interconnection charges under the current TPM.

3. Objectives for a New Zealand TPM

3.1 The Rules and the Terms of Reference

3.1.1 The Rules

Rule 2 in Section IV of Part F of the Electricity Governance Rules (the Rules) sets out some pricing principles for the TPM, which Transpower and the Electricity Commission must follow. Rule 3 provides guidance on the application and interpretation of the pricing principles.

3.1.2 The Terms of Reference

a) Decision criteria

The Terms of Reference for the project contain specific decision criteria and guiding principles. The Working Group in its deliberations is required to apply the following decision criteria in relation to proposals:[7]

- effectiveness (i.e. the TPM must be capable of enforcement)
- accountability (i.e. clear accountabilities must be specified and understood)
- credibility (i.e. the TPM must be credible and acceptable to all stakeholders - industry participants, consumers and regulators)
- transparency and clarity (i.e. the TPM must be clear and readily understandable)
- simplicity (i.e. the TPM should avoid unnecessary complexity)

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[7] Terms of Reference, 2.16.

- decision making features (i.e. decisions should be made by those parties with the best incentives and information)
- transaction costs (i.e. these should be minimised)
- flexibility and certainty (i.e. the TPM should promote the ability for arrangements to evolve, balanced against the need for certainty) and
- legality (i.e. the TPM should not be unlawful).

b) Guiding principles

The guiding principles that the Working Group should be cognisant of during its deliberations are:[8]

- the role that transmission has to play in the development of a vibrant first world economy and its growth aspirations
- the critical role that transmission has to play in the development and encouragement of competitive generation and retail markets
- the need to provide transmission services at the standards of quality and security required by grid users through a process of agreement with those users
- the desirability, where appropriate, to support and encourage the contestable use and development of transmission services
- the need for transmission services to be continuously improved so as to produce the services users want at least cost
- ensuring that the services are priced in a manner that:
  - is transparent
  - fully reflects their costs including risks
  - facilitates nationally efficient supply, delivery and use of electricity
  - facilitates, where appropriate, the use of locational signals bearing in mind existing locational signals in the market
  - promotes efficient use of Transpower's resources and
  - promotes nationally efficient use of transmission services by grid users and so facilitates efficient resource use and
- the current Pricing Principles set out in Part F, Section IV, Rule 2 of the Electricity Governance Rules.

3.1.3 NERA's approach

In the Report NERA does not pay much explicit attention to the pricing principles in the Rules or the related guidance. Nor does it consider explicitly its high-level options relative to the decision criteria and guiding principles provided to the Working Group under the Terms of Reference. NERA defines its task as "to explore ways in which to improve the efficiency of electricity transmission pricing arrangements in the New

[8] Terms of Reference, 4.1.

Zealand Electricity Market."[9] To NERA, its task is to develop options for reform of the TPM by "enhancement of economic efficiency through altering the commercial incentives facing market participants and ultimately their decisions/conduct".[10]

3.1.4 Our approach

To pay limited attention to the pricing principles in the Rules is arguably a sound approach because they are not easy to understand and some industry participants have argued that they are not internally consistent and difficult or impossible to apply consistently in practice. Moreover, it is likely that if a widely accepted TPM with good efficiency properties were developed, it would be adopted, even if this required some amendment to the pricing principles in the Rules. To not explicitly consider the guidance provided by the Terms of Reference is less understandable. In developing our recommendations we will follow NERA and not focus on the pricing principles in the Rules. However, we will briefly evaluate the alternative options we develop against the decision criteria and guiding principles in the Terms of Reference.

3.2 First principles

3.2.1 Why have a TPM?

The reason we need a TPM is that, in some situations, if it was left to the market to determine who would pay for transmission assets and how, the outcome, in terms of investment in assets and the incidence of charges, would not be efficient.

There are economic advantages from increased security of supply and increased competition among generators resulting from sharing the interconnected components of the grid network on an open access basis. But, if there is open access and sharing, each party has an incentive to avoid payment for use of the common assets, if it can. Free riding could be a potential issue. To the extent there is free riding, the outcome will be inadequate investment in shared transmission assets relative to the optimal level.

Moreover, since many transmission assets, once installed, are specialised and have a limited value in an alternative use, a transmission asset provider is vulnerable to opportunistic behaviour by users refusing to pay for the costs associated with the "sunk" assets. As a result of this risk, investors in transmission assets will be reluctant to invest without satisfactory assurance they will receive payment. Such assurance can come from either long-term contracts with credit worthy counterparties or a regulatory enforced obligation to pay being imposed on some parties acceptable to the transmission asset provider.

The potential free riding problem can be effectively managed if transmission asset owners have the ability to disconnect or not connect parties who refuse to pay, and are willing and able to enforce this right. In New Zealand, Transpower, as the

[9] NERA, p. i.

[10] NERA, p. i.

transmission asset owner, has the legal right to disconnect parties and refuse to connect parties for non-payment, but in practice it has not felt able to exercise the right to disconnect generators and/or distributors, whilst it has for direct connect customers. Presumably, this is because if it did so, disconnection would quickly and potentially severely adversely affect a number of third parties and so would be politically unacceptable to Transpower's shareholding ministers.

Voluntary long-term contracting is the basis on which investment in connection assets is undertaken in New Zealand. Indeed, any party, and not just Transpower, can invest in transmission assets and as a result the provision of connection assets is a contestable market and not currently subject to the regulatory control of the Commerce Commission under Part 4 of the Commerce Act or oversight by the Electricity Commission.

3.2.2 The alternative to a TPM

Voluntary long-term contracting was tried in New Zealand as a basis for investment in interconnection assets from the early 1990s until 2003. It is often claimed that the approach proved to be a failure and led to significant under-investment. The reality is, however, that for much of this period little investment in the interconnected grid was proposed by Transpower, or anyone else, and most investment proposals intended to improve security were supported by customers.

In the main, customers either agreed to a special charge to pay for projects or met the costs under Transpower's posted terms and conditions. The well known dispute over payment for the HVDC between Transpower and Meridian Energy was not a dispute about who should pay for new investment in the interconnected grid; it was a dispute about who should pay for the existing HVDC asset. Many of the other disputes in the 1990s were also about Transpower's posted terms and conditions for existing assets and not about funding investments in grid upgrades.

The version of the Rules that relate to transmission developed by the Transport Working Group (TWG) under the Electricity Governance Establishment Committee (EGEC) incorporated the long-term contractual approach to approving and funding interconnection transmission investments. It allowed for the parties to negotiate payment terms and conditions among themselves and the decision to be made by a 75% majority, with votes allocated on the basis of future expected financial contribution to the assets under the proposal for its funding. The 75% majority was designed to overcome hold-out by some parties seeking preferable terms for themselves in proposals.

The role of the TPM under Part F of the EGEC Rules was to allocate costs for existing interconnection and connection assets for which there was no contractual basis for payment. The EGEC version was never implemented, and instead a regulatory approach to decision making about investment in interconnection assets was developed.

The advantage of the voluntary long-term contractual approach is that, if hold-out is not possible, it equates to the outcomes in a market situation. As such, it can be expected to produce efficient decisions about what investments should be undertaken, when and by whom, and about which parties should bear the economic costs of investments both now and in the future.

3.2.3 A TPM to replicate voluntary contracts

The discussion in the previous section suggests to us a general approach to developing a TPM with desirable efficiency properties: to allocate transmission related costs in a manner as close as possible to how they would have been allocated if the investment in the assets had been backed by voluntarily agreed long-term contracts between the transmission service provider and others, in a world in which free riding and hold-out are not possible.

Which parties pay when the decision is made by voluntary agreement between buyers and sellers and free riding and hold-out are not possible? The answer is clearly that the beneficiaries pay when there are positive net benefits. Only parties that receive a net benefit from the good or service have the motivation to voluntarily pay and they only demand as much as will yield them a higher net benefit than alternative uses of their money. Beneficiaries may not pay if they can free ride or if they believe that, if they hold out in negotiations over payments, they will be able to force costs on to others. But if the only way to acquire a good or service which yields positive net benefits is to pay, beneficiaries will pay and only beneficiaries will pay voluntarily.

This suggests that, to achieve efficient outcomes, the TPM should, as far as practicable, allocate costs to beneficiaries and allocate no more than a beneficiary would pay voluntarily if that was the only means available to acquire the good or service.

3.2.4 Application of approach in current TPM

Beneficiaries pay is in essence how the current TPM allocates the costs of connection assets. These are paid for under long-term contracts by the connected party or parties, whether they are a generator, distributor or direct connect customer.

This is obviously how a connection asset with only one user would be paid for if this was left to the market. For connection assets with several users the charges are shared on the basis of their anytime maximum demand (AMD) or anytime maximum injection (AMI). It is likely that even if the parties were left to negotiate and agree the allocation among them of costs for shared connection assets, they would come up with a similar outcome as it is the maximum demand or injection that drives the size of the connection assets required and hence their costs. Even the ”deep connection” definition used in the current TPM can be interpreted as an application of this approach. The definition used is such that if the beneficiary of an asset can be identified, it is generally a connection asset, and for connection assets the beneficiary or beneficiaries can typically be reasonably readily identified.

4. Aspects of transmission pricing

Can the approach to designing a TPM discussed in the previous section be extended to apply to charges for transmission assets other than connection assets? There appear to us to be two circumstances where this is worth exploring:

- the HVDC link and
- major upgrades to the interconnected network necessitated by either connection of a new generator or a significant new load.

4.1 The HVDC link

4.1.1 Beneficiaries of the current HVDC link

a) South Island generators?

South Island generators are clearly beneficiaries of the current HVDC link in the sense that they would pay for it if it was the only way to gain access to its services. The existence of the link raises the average price received by South Island generators.

b) North Island load?

Whether the link lowers the prices paid by North Island load over the medium term is much more questionable. The price of electricity in the wholesale market place is set by the marginal plant and tends in the medium term to reflect the LRMC of thermal generation. If the link was cut, the price in the North Island would in the medium-term continue to reflect this as new capacity is added in the North Island to replace the South Island capacity formerly accessed over the HVDC link. Thus, apart from a short-term hiccough, disconnection of the grid would not materially raise the prices faced by load in the North Island; consumers in the North island are not material beneficiaries of the HVDC in an economic sense.

c) South Island load and North Island generators?

It is sometimes argued that because power flows over the HVDC from north to south from time to time, and on occasion for extended periods, South Island load and North Island generators are also beneficiaries of the HVDC link. The economic test of whether a party is a beneficiary is whether it would voluntarily pay for something rather than go without. We doubt that more than a handful of South Island consumers would voluntarily pay for the HVDC link because most would realise that without the prior draw down of South Island lakes to send power north, there would be little likelihood of a need to import North Island power. Moreover, without the HVDC, prices for electricity would be significantly cheaper on average for a considerable period into the future. Low prices would last until extra South Island capacity would be required to meet South Island demand. We also doubt any North Island generator would voluntarily enter into a long-term contract to pay for the HVDC link in order to access the South Island market.

So, an attempt to replicate the outcome if the current HVDC link had been funded by long-term voluntary contracts would almost certainly result in the charges falling upon South Island generators alone. This is how the charges fall under the current TPM.

d) Allocation among South Island generators

But how would the charge be allocated among South Island generators? We believe there would be a tendency for the burden of cost to be related to the level of benefit derived. Those generators with the largest surplus of electricity over local requirements and which tend to produce at times of the day and seasons of the year when, in the absence of the HVDC link, the inter-Island price differential would be at its greatest, would tend to bear a larger burden of the costs. In practice, this would be generators with plant forming parts of the Waitaki and Clutha systems.

If the HVDC link exists, the electricity price in the wholesale market will be higher for all generators in the South Island, so they will all benefit to this extent. Therefore, we would not expect the differential burden of the link's cost between the various South Island generators derived on the basis of their location to be large. Although it is unlikely any of the output from Cobb or a station on the West Coast would reach Benmore and be exported to the North Island over the HVDC link, the price received by Cobb would be very much lower if there was no HVDC link, so its owner is a material beneficiary of the link even though its power does not flow across it.

These considerations suggest a minor modification to the current HVDC charge, to incorporate a small element of the charge being based on the net balance of the area in which the South Island generator is located, may improve its efficiency. However, allocating all the HVDC link explicitly to South Island generators is contentious in itself and in our opinion it is unlikely that tilting of the HVDC charge so it falls more heavily on South Island generators in some locations than others will be any less contentious. The basis for the tilting will engender its own debate and controversy.

4.1.2 Beneficiaries of the HVDC link upgrade?

Whether the recently approved upgrade and expansion of the HVDC link would have been funded if the negotiation of long-term contracts with interested parties to bear the cost had of been necessary is uncertain. All the South Island based generators indicate they would not voluntarily pay for the expanded link at this time. This suggests that voluntary funding may have been difficult. On the other hand, it is unclear how much these statements are posturing by generators to try to get the administration to agree to a revision of the HVDC charge and its reallocation to other parties.

If, however, it is correct that the South Island based generators would not pay for the upgrade because they do not think they would derive sufficient benefit from it to warrant the expense it would impose on them, then, assuming no other parties would willingly pay, the upgrade is not an efficient use of New Zealand's scarce resources and the project should be cancelled. A corollary is that the current decision making process using the grid investment test (GIT) is leading to inefficient investment decisions and its application needs to be changed.

4.1.3 Alternative charging regimes for the HVDC link

There are two other means of charging for the HVDC link suggested by trying to replicate how long-term contracts would allocate its costs. We shall refer to these as the capacity rights approach and the arbitrageur approach.

a) The capacity rights approach

Under this approach the owner of the HVDC auctions time and day specific capacity rights to use the link and a secondary market for the trading of these capacity rights is established. Any party can bid for the rights in an auction, and rights are transferable. But only parties that hold rights relating to the time and day are dispatched by the system operator if, by doing so, energy is injected into the HVDC link. The HVDC loss and constraint rentals could be attributed to the holders of the capacity rights at the times they arise.

This approach is possible on the HVDC link because the flow across the link can be determined, as can the effect of dispatching each MW from each generator on the flow that will occur. The capacity rights would apply to the transport of electricity in either direction because, at any instant in time, electricity has to be flowing in only one direction or not flowing at all. This approach to charging for the HVDC would also ensure that the party that would benefit most from sending power across the HVDC link would do so as it would pay the most for the capacity rights. As a result, this approach should tend to produce efficient outcomes with a minimum of administrative involvement.

Would the revenue raised from the auctioning of rights fully cover the costs of the HVDC asset owner providing the service? They should if the benefits derived from using the link exceed the costs of providing the link as parties should be willing to bid up to the level of benefit they expect to derive from owning the rights. If payments for capacity rights do not cover the costs of the link, then the link is inefficient in the sense that its economic benefits are less than its costs. That this social loss should fall upon the HVDC link owner – Transpower – is appropriate as it was the party which decided to build the link. On the other hand, if the auction raises more than the costs of providing the link, then the excess returns could be pro-rated back to the successful bidders on the basis of the amount they bid.

The auctioning of capacity rights could be extended to the upgrade of the HVDC link in a contestable manner. An investor would only build an additional link if it was confident it would be able to sell capacity rights for now and in the future for sufficient value to cover its costs. This would tend to result in the upgrade occurring if and when it is economically efficient. It would not mean that the value of existing capacity rights would have to be very high before an expansion would occur because an investor in a contestable situation would look not just at current demand for extra capacity but expected future demand and decide when is the optimal time for it to invest, knowing that if it delays too long another party may gazump it.

b) The arbitrageur approach

Under this approach the owner of the HVDC link would arbitrage between the markets for electricity in the two islands by buying in one and selling in the other. It would keep the difference between its revenue from sales and its costs from purchases and the HVDC loss and constraint rentals as its return to cover its costs of capital and operating expenses.

The arbitrageur would be subject to a requirement that it earn no more than the weighted average cost of capital (WACC) and its actual operating costs on this activity. If it should earn returns above its permitted level, these would be rebated back to those it purchased electricity from during the period on a *pro rata* basis. This would constrain the ability of the HVDC arbitrageur to exercise market power.

On the other hand, if the arbitrageur is unable to fully cover its costs then the HVDC link is inefficient in the sense that its economic benefits are less than its costs. That this social loss should fall upon the HVDC link owner – Transpower – is appropriate as it was the party which decided to build the link.

An advantage of this arrangement is that it would effectively remove all arguments over which parties should contribute to the costs associated with the HVDC link. It could also cater for decisions on whether to expand the link without regulatory involvement and ensure that the parties making the decision on whether or not to invest wear the risks that the expansion is not an efficient use of resources. The arbitrageur, or someone else wishing to enter this market, would make its own decisions on the value of the price differential between the islands and whether or not it is rational to invest in expanding the link in order to capture some of this differential. There would be no need for the Electricity Commission to be involved in assessing proposed investments.

4.2 Major upgrades

In the PJM market, generators that wish to receive capacity payments for a plant they want to connect to the grid are required to fund any upgrades to the grid network that would not be required "but for" the need to deliver the output of the plant to meet the requirements of load. In return for funding the upgrade, the generator is not only entitled to capacity payments for its generation plant but also receives long-term Financial Transmission Rights (FTRs) for the increase in transmission capacity it has funded.

The same "but for" approach could be applied to major upgrades of the New Zealand transmission system necessitated by the connection of new generation or a significant new or additional load. That there are no capacity payments available for generators in New Zealand does not appear to be an inhibitor to adoption of the approach, despite Frontier Economics claiming this is the case in a recent draft paper for the Electricity Commission. The role of capacity payments in the PJM scheme is to trigger the need for generators to seek transmission upgrades. What is required is a FTR regime and rules to identify whether a new or additional load will be subject to charges on this basis and the rules to define what investments in the interconnected grid will be assigned and paid for on a "but for" basis.

This approach is an extension of what would occur in a market if the only way to ensure necessary grid investments occurred was by entering into long-term contracts. The transmission service provider would seek a long-term contract from new generators and significant additional load to cover its costs and ensure it is not left with sunk assets and vulnerable to opportunistic behaviour by connected parties. On the other hand, the connecting party would seek assurance that as a result of paying for the grid upgrade it would have access to use the assets in future and be compensated for the economic effects of other parties using the capacity. The FTRs would meet this requirement.

It would not be practical to apply the "but for" approach to every small increase in load; the transaction costs involved in modelling and costing the increment in assets required would not be worthwhile. On the other hand, we do not think it is difficult to identify what assets would be required to be funded, and for what period of time, on a "but for" basis. The connecting party might not be required to pay for all the grid upgrade undertaken by the transmission service provider. If there are economies of scale, the service provider may decide a bigger upgrade than what is required by the connecting party would be optimal. In this situation the connecting party would be required to pay for the upgrade which would have been necessary to just meet its requirements and would receive FTRs accordingly.

There is no reason why the "but for" approach should not be applied to both economic and reliability investments in the grid. The test for when to apply is whether it is possible to identify the beneficiaries of the investment at a reasonable cost. An issue which will arise is whether it should be applied retrospectively. Should, for example, the upgrade of the costs of the 400 kV upgrade of the Whakamaru-Otahuhu line be allocated to consumers in Auckland and northwards on the grounds that they were the beneficiaries of the improvement in reliability the upgrade is supposed to provide? Since the beneficiaries can be identified reasonably clearly in this case we see no reason why this should not happen. The Electricity Commission warned at the time the investment was being discussed that payment for it might be targeted to its beneficiaries under a future transmission pricing methodology.

5. Evaluation of additional high-level options

5.1 The alternative high-level options

The additional options we suggest are:

- Alternative Option A: The status quo TPM but with the current HVDC charge replaced by payment for the HVDC link according to the capacity rights approach outlined in the previous section.
- Alternative Option B: The status quo TPM but with the current HVDC charge replaced by payment for the HVDC link according to the arbitrageur approach outlined in the previous section.
- Alternative Options C: The status quo TPM but with the current connection charges supplemented with additional charges on new generators and new load over a *de minimus* level based on the "but for" approach outlined in the previous section.
- Alternative Option D: The combination of Option A for the HVDC link and Option C for assets built as a result of new connections.
- Alternative Option E: The combination of Option B for the HVDC link and Option C for assets built as a result of new connections.

5.2 Comments on Alternative Options A and B

5.2.1 The decision criteria

Advantages of Alternative Options A and B in terms of the decision criteria are that both are:

- reasonably simple
- clear and readily understandable and much more so than NERA's TPS or bespoke TPS proposals
- able to ensure that decisions about investing in and using HVDC upgrades are made by the parties with the best incentives and information and
- able to cater for changes in circumstances relating to the use of the HVDC and which parties are its beneficiaries; more specifically, could handle the predominant flow becoming north-south.

In addition, Alternative Option B – the arbitrageur approach – would:

- minimise transaction costs and
- be credible and acceptable to (most) stakeholders.

The stakeholder that might object to the arbitrageur approach is Transpower as this approach would involve it in commercial risk. Transpower has a long history of passing any conceivable risk on to its counterparties to the point where it is unclear why regulators allow its shareholders to receive a return for equity risk rather than a high-grade bond yield reflecting the credit worthiness of its counterparties collectively.

Transpower's concerns could be overcome if it divested ownership of the HVDC link to another party willing to take on the arbitrageur's risk. This new party could be left to decide in a contestable environment whether or not it wants to invest in expanding the HVDC link.

Alternative Option A - the capacity rights approach – would incur considerable transactions costs in trading capacity rights between parties. Transpower is also likely to object on the grounds that this approach would leave it with some risk over its return, although divestment to a party willing to bear such risks would resolve this problem. Generators are also likely to object to this arrangement as the obligation would be on them to have HVDC capacity rights. They are likely to perceive this as requiring them to continue to pay for the HVDC link.

One advantage that both Alternative Option A and B would achieve relative to the status quo (and the Options proposed by NERA) is to remove any disincentive on the establishment of peaking plants in the South Island. Since a genuine peaking plant would only operate when the HVDC flow is from north to south or when the HVDC link is out of service altogether, under both approaches, a South Island peaking plant would not bear any costs of the HVDC link. Both approaches would also result in generation plants that tend to operate proportionately more often at times when the flow on the HVDC link is near capacity would receive a price signal reflecting the scarcity of the resource it wishes to use. The options proposed by NERA would not provide such a price signal.

5.2.2 The guiding principles

Advantages of Alternative Options A and B in terms of the guiding principles are that both:

- support and encourage the contestable use and development of transmission services, especially if Transpower decides on divestment of the HVDC link rather than face the increased business risks implicit in both alternative options
- support efficient pricing and
- are consistent with the current pricing principles in the Rules because they would attribute costs to beneficiaries.

5.3 Comments on Alternative Option C

5.3.1 The decision criteria

Compared with the status quo the “but for” approach would slightly reduce:

- transparency and clarity
- simplicity and
- certainty.

It would also increase transaction costs and require the introduction of FTR’s, although that is a likely development anyway.

Against this, however, it would increase the extent to which decisions about the location of new generators and significant load would be made by parties with the best incentives and information pertinent to the decision.

5.3.2 The guiding principles

Option C appears to us to be consistent with the pricing principles in the Rules and would contribute towards ensuring that transmission services are priced in a manner that provides more efficient locational signals and the efficient use of the grid and resources.

6. Recommendations

We recommend that the MEUG representatives request the Steering Group to add Alternative Options D and E to the high-level options being considered by NERA and the Working Group.

Alternative Option D is the status quo TPM but with:

- the current HVDC charge replaced by payment for the HVDC link according to the capacity rights approach and
- the current connection charges supplemented with additional charges on new generators and new load over a *de minimus* level based on the “but for” approach.

Alternative Option E is the status quo TPM but with:

- the current HVDC charge replaced by payment for the HVDC link according to the arbitrageur approach and
- the current connection charges supplemented with additional charges on new generators, and new load over a *de minimus* level, based on the “but for” approach.

We also recommend that the Working Group be asked to explicitly consider each option it evaluates in terms of the decision criteria and guiding principles set out in its Terms of Reference.