24 February 2012

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Consultation Paper – Decision-making and Economic Framework for Transmission Pricing Methodology Review

Thank you for the opportunity to comment on the Electricity Authority's (EA) consultation paper on the proposed framework for the Transmission Pricing Methodology Review. No part of this submission is confidential. MRP's response to the detailed consultation questions are outlined in the attachment to this response. However, we wish to emphasise key points in this covering letter which forms the essential part of our submission.

Mighty River Power (MRP) notes the paper presents one of many theoretical frameworks which could be applied to the Transmission Pricing Methodology. Effectively, the paper represents a blank sheet approach, whereby the EA are canvassing opinions on mechanisms which have been considered in significant detail, including modelling of efficiency benefits, by various groups in the course of successive reviews on aspects of the TPM stretching back over a decade. These include the:

1. Transport Working Group of the Electricity Governance Establishment Committee (2001-2)
2. Transmission Pricing Steering Group, part of the electricity industry's CEOs Forum (2009)
3. Transmission Pricing Technical Group, part of the Electricity Commission Review (2009-10)
4. Transmission Pricing Advisory Group, independent advice provided to the Electricity Authority (2011)

We consider that the latest paper from the EA does not introduce any new analysis or approaches that have not been robustly and comprehensively reviewed in the past. In this regard we find it unlikely that, without any new or compelling approaches or evidence coming forward, that significantly different conclusions will be reached.

In the interim, the current delays associated with resolving an appropriate framework are creating regulatory uncertainty. This is particularly significant for those entities like MRP which are subject to the Mixed Ownership Model process.

We appreciate that aspects of the TPM, particularly HVDC pricing, are controversial and as such the EA are seeking to establish a robust consultation process. However, we consider that despite the conclusion in the paper that TPAG was unable to reach a consensus on some areas of the TPM, TPAG made recommendations on every aspect which we consider cannot simply be ignored. The EA should seek to take forward these recommendations which would be more efficient and effective in our view than re-opening the debate.

<u>HVDC pricing</u>

TPAG identified a number of inefficiencies with the current TPM in relation to HVDC cost allocation including:

a) Possible generation investment inefficiency from delaying South Island generation;
b) Competition effects between South Island generators resulting from the HVDC charge; and
c) Generation investment and dispatch inefficiencies from the HAMI price structure.

The main dispute within TPAG was not around the veracity of these inefficiencies, but whether they were material enough to warrant changes to the TPM. The clear recommendation from TPAG was to undertake further analysis to clarify the quantum of efficiency losses and use this as a basis to support either a proposed transitional postage stamp approach or the status quo.

We support the principles and approach within the TPAG process. Given the EA objective of acting in the long term interest of consumers, the EA should take forward the recommendations outlined in the TPAG final report to verify the potential quantum of efficiency losses and then use this as a basis to make a final decision.

While we are not directly impacted by the status quo, MRP supported the TPAG postage stamp transition on the basis it: was a stable and durable outcome; dealt effectively to the current inefficiencies; and the long transition period effectively addressed the wealth transfer impacts.

We also support the recognition in the TPAG report that, given transmission regulation has now transferred to the Commerce Commission, the EA should consult more directly to develop a pricing framework given it has jurisdictional implications for the Commerce Commission.

Exacerbator and Beneficiary Pays

The paper establishes a hierarchy of so-called administrative approaches, allocating transmission related costs based on an exacerbators pay and beneficiary pays basis. These approaches have been considered in different guises in the past.

We agree that at the fringes of the grid where exacerbators and beneficiaries can be more easily identified there is merit in allocating cost on this basis. However, as noted in TPAG there are significant and potentially insurmountable difficulties in identifying such groups deeper within the grid which leads to conclusions that more aggregated pricing approaches, such as postage stamping, are likely to be more efficient at this level.

Our main concern revolves around the suggestion in the paper that exacerbator and beneficiary pays should apply *ex post* to send appropriate investment signals to investors. We consider this outcome would be undesirable against the EA's own efficiency objective as it would result in:

a) an immediate reduction in the value of assets that had been constructed which are unable to respond to the locational signal; and
b) The deferral or cancellation of proposed generation and as such under-utilisation of the transmission infrastructure.

We consider that such approaches if applied, should only be on a prospective basis. Providing decision rights to generators to assess the private benefits of incurring connection costs before committing to an investment should also be implemented.

Incentives for Grid Disconnection

The paper also questions whether further analysis is justified on the risks to direct connect customers removing themselves from the grid due to increasing transmission costs. We do not consider this to be a likely outcome on the basis that:

- It would entail the management of costs and risks which are not core business to direct connect customers;
- There are significant flexibility, efficiency and security benefits associated with grid connection;
- The Whirinaki sale price does not represent an credible proxy for the likely costs of back-up generation;

- There are issues with the EA's assumptions around the per KW price and utilisation rates which suggest actual back-up costs could be much higher; and
- The materiality of the issue is actually far lower than implied in the EA analysis and is in our view, immaterial.

In conclusion, we consider that the development of the TPM should avoid applying overly theoretical complexity to a market the size of New Zealand. Significant analysis has been undertaken by numerous reviews which cannot be ignored and should be used as a basis to resolve long-standing issues, such as HVDC cost allocation. In this regard, our view is that the overwhelming evidence suggests the HVDC operates as an interconnection asset and that the costs should be allocated on this basis. The TPAG postage-stamp achieves this outcome in a durable and stable way which we support.

Please direct any queries on this issue to Nick Wilson, Senior Market Regulatory Adviser on nick.wilson@mightyriver.co.nz or 09 580 3623.

Yours sincerely

Fraser Whineray
General Manager Operations

Attachment 1 – Questions and Answers

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

Yes, with some minor modifications. We agree the focus on the development of the TPM should seek to promote the lowest cost development of the industry over time as this is clearly likely to benefit consumers in the longer term, consistent with the EA's overarching statutory objective.

In terms of the first objective outlined in section 3.4.2(a), we consider that this could be further modified to capture some of the more nuanced discussion found later in the paper and from the analysis contained in the TPAG final report. As a suggestion:

> 'efficient use of the grid focuses on least cost production and charging customers the efficient marginal costs of production *where such costs can be efficiently and reliably identified'*

We also support the recognition in the paper that costs of regulatory uncertainty on investment and the efficient operation of the market are important. Key from MRP's perspective is that a durable and enduring solution to transmission pricing is established that provides regulatory certainty.

The TPM has now been subject to several high profile reviews all of which have provided robust, principled and defensible evidence to suggest that change to the TPM is warranted against the efficiency criteria identified by the EA. We have concerns that taking the debate back to first principles will not ultimately result in new information or perspectives but consume further time and resources to reach similar conclusions.

In relation particularly to HVDC pricing, we support the recommendation from TPAG for the EA to undertake further GEM analysis to verify the efficiency impacts and then take a decision on the two options proposed by TPAG.

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

While we broadly agree with application of the three limbs, we question some of the examples of how transmission pricing can influence competition. In particular we find it unlikely due to a number of factors that increasing transmission charges will result in direct connect customers disconnecting from the grid. These arguments are outlined in Question 14 below.

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

While in theory a market-based TPM should tend to promote efficiency and should form a preferred approach, transmission networks display a number of characteristics that make the application of market-based mechanisms problematic.

MRP considers that if a market based TPM is to be considered, its implementation needs to be balanced against a robust and defensible assessment of the likely efficiency gains versus the costs of implementation of any new mechanism against the status quo. This was the approach adopted by TPAG which we support.

The following provides commentary on the two market mechanisms, long-term contracting and capacity markets, highlighted in the paper.

Long-Term Contracting

As noted by TPAG: "…economies of scale, monopoly characteristics and common good aspects all make it difficult for a pure contracting model to work efficiently.[1]". TPAG also illustrates that the experiment in New Zealand with locational marginal pricing has not resulted in the hoped for market-driven pricing and investment in transmission services.

The paper highlights that the Transport Working Group (TWG) in 2001-2 specifically considered the issue of how the barriers to a long-term contractual model could be addressed. However, the context of this review was to develop transmission investment as part of a voluntary industry framework. Since that time the industry has been subject to regulation and the jurisdiction for transmission investment has shifted to the Commerce Commission. It is therefore questionable whether the EA has the appropriate jurisdiction to

[1] TPAG final report (August 2011) pg 16

be considering changes to the TPM framework around long-term contracting without appropriate consultation.

The solutions suggested from the TWG process, while potentially workable within the context they were developed, would likely not be suitable today. As noted in the discussion paper, most of the grid upgrade expenditure over the coming years has been allocated by the previous Electricity Commission. The TWG approach if implemented would not address the more significant issue of how the sunk costs associated with existing transmission infrastructure are allocated.

Furthermore, we consider a long term contracting model has the potential to lock in industry structures and reduce the dynamic efficiency benefits that many of the EA reforms have been striving to achieve; particularly encouraging nationwide retailing and increased competition. This would not be consistent with the EA's objectives of acting within the long-term interests of consumers.

As principle we consider that a workable long term contractual arrangement is predicated on the ability for parties who are potential beneficiaries or so-called "exacerbators" to have the right to decide how the costs compare to the potential private benefits.

<u>Capacity Pricing</u>

The paper also considers a capacity pricing approach for application to the HVDC. MRP does not support further analysis on the capacity rights mechanism at this stage. Instead, resources should be allocated to undertaking the GEM analysis recommended by TPAG as the basis for EA to make a decision on either the transitional postage stamp or status quo for HVDC pricing.

The reasons for this conclusion is on the basis that capacity pricing has been extensively reviewed in numerous forums and reviews including the Transmission Pricing Steering Group of the electricity industry's CEOs Forum, the EA itself through the Transmission Pricing Technical Group (TPTG) and most recently TPAG.

The EA report noted that there were significant practical implementation issues associated with the capacity rights proposals, including significant revisions to the market clearing engine, transaction costs for smaller generators, interactions with scarcity pricing and financial transmission rights and system security[2].

[2] Electricity Authority (Nov 2010) NZIER Capacity Rights Proposal - Implementation Issues (Nov 2010)

TPAG also noted that while an assessment of the costs of capacity rights was beyond its scope, these costs were likely to be higher than other options. Capacity pricing, in its view, would also introduce "possible complexities for Transpower, hedging, system security and market power" and would entail major market redesign[3].

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

No – on the basis of the points raised in the previous question – we do not agree. With specific regard to HVDC pricing, the most durable and stable option in MRP's view is the postage stamp transition proposed by TPAG (See response to Question 15).

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

No. As highlighted above, numerous reviews have already clearly, credibly and comprehensively analysed the various options for transmission pricing. Against the EA's own criteria, it is unlikely an efficient or practicable market-based option can be identified. Fundamentally electricity transmission is a monopoly asset, the pricing of which the theory would suggest is best approached administratively.

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

No – see responses to Q3 and Q4. As above, we consider the most efficient approach at this stage is to take forward the analysis proposed by TPAG on HVDC pricing (See response to Question 15).

Q7. Do you agree the Authority's second, third and fourth ranked preferences should be to adopt the administrative approaches to TPM charges of exacerbators pay, beneficiaries pay

[3] See Footnote 1, pg 70 and 86.

and other charging options wherever it is confident such charges will be efficient, implementation will be practicable, and that any Code amendments needed comply with the Authority's Code amendment principles? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?

Our comments to this question relate to the workability of the administrative approaches suggested. As the paper touches on, to a large extent many of the large transmission investments that are expected to deliver benefits over the next two decades have now been committed under the existing TPM. It is therefore questionable to what extent the proposed framework will be able to influence any generation investment decisions even if, as is discussed with regards to the exacerbators and beneficiaries pay options, mechanisms might be applied in retrospect.

This outcome would be undesirable against the EA's own efficiency objective as it would result in:

a) an immediate reduction in the value of assets that had been constructed which are unable to respond to the locational signal; and
b) The deferral or cancellation of proposed generation and as such under-utilisation of the transmission infrastructure.

These outcomes are clearly undesirable from an efficiency perspective and the long run interest of consumers. These inefficiencies are likely to be compounded by the fact that the identification of beneficiaries and exacerbators (as opposed to simply users) within the shared network becomes increasingly more difficult and therefore more costly in implementation.

MRP recommends the EA should consider whether the proposed exacerbators and beneficiaries pays approaches, while theoretically correct, are likely to be economically efficient in practice against its own objective and not give rise to perverse outcomes. This is particularly relevant if the principles are to be applied in retrospect. The response to the following question provides further discussion on the potential impacts of an ex-post application of exacerbator pays.

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

The paper uses a roading analogy to illustrate how potential generation and load investments can result in additional costs to augment the shared network. It is argued efficiency would be enhanced by ensuring that exacerbators face these additional costs. Critical to the EA's example is that efficiency is derived from the fact that exacerbators have the ability to modify their investment decisions on the basis of understanding the potential costs they would face.

As noted above, MRP has concerns that proposals to implement the exacerbators pays approach retrospectively to serve as an example to others to consider their indirect costs to society is misguided. Generation investments that have been constructed on the basis of a presumed transmission cost have no scope to respond to the locational signal provided and have no choice but to bear the additional charge, effectively as a tax, to the extent increased asset utilisation is not possible. Any losses incurred in turn increases the hurdle rate for future generation investments.

In addition, an exacerbator pays approach is also likely to incentivise generation investment in less congested areas of the grid close to load, which is likely to be higher cost thermal generation. In areas where there are lower cost renewable resources, under an ex-post application, committed generators will incur exacerbator costs which will have to be recovered (if possible). For consumers, this means that any benefit from avoided transmission charges would likely be offset by increasing wholesale energy costs.

As a result, the application of an exacerbator pays approach requires careful consideration. We consider that the concept, if implemented, should only apply on a prospective basis. Providing decision rights to generators to assess the private benefits of incurring connection costs before committing to an investment was also a recommendation from TPAG and should also be implemented.

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

Effectively there are only two factors that can be considered exacerbating factors in transmission investment:

1) Load: Increasing demand exacerbates transmission when local demand exceeds the ability of local energy sources to supply that demand economically; and
2) Location: generation can directly influence whether transmission building is exacerbated by being built further away from demand than other sources of energy.

For the avoidance of doubt, generation cannot be an exacerbator simply by virtue of its size, as generation is required to meet demand and cannot exceed it except for momentary frequency variations. Indeed, deterring generation from meeting demand is counter-productive and clearly not in the best interests of consumers.

By seeking to provide increased locational signals, the exacerbator pays approach is most similar in concept to the 'but for'[4] option, which was considered by TPAG. Numerous locational pricing approaches have been canvassed in successive reviews of transmission pricing including by the Electricity Commission. With the exception of HVDC pricing, the broad conclusions of past reviews and TPAG has been that:

> "The benefits of enhancing locational signals for economic transmission investments are not sufficient to justify changing the TPM to provide additional locational signalling for economic transmission investments"[5].

With specific regard to the "but for" option, TPAG noted while the approach could be broadly workable the efficiency gains were relatively low and potentially not sufficient to justify the significant wealth transfers and pricing impacts. It would also be inherently more complex than the status quo and subject to a number of implementation issues including:

- Requiring co-ordination with the Commerce Commission via the transmission investment approval process;
- Lacking durability due to susceptibility for disputes over the identification of beneficiaries and beneficiary shares;
- Differing treatment of old and new assets and issues where existing assets need to be refurbished or replaced;
- Wealth transfers – would be dependent on the threshold but could be substantial for some customers;
- Very significant price impacts for new individual customers involved in each new investment; and
- Could fit with existing market but dependant on whether any decisions rights were allocated over assets.

We consider that many of these issues could also apply to the application of an exacerbator pays approach, noting the emphasis is somewhat different. As indicated above, the implementation of an exacerbator pays approach as with 'but for' would apply to new assets

[4] 'But for' involves a one-off identification of beneficiaries of new deep connection assets and a greater allocation of resulting costs when approved under the GIT.

[5] See TPAG final report pg 28 3.4.5(b) and also pg 23, 3.3.1(a)

and as such would provide no guidance on the treatment of costs in the more controversial areas of the TPM, in particular the HVDC.

In terms of an alternative approach, we note that the one aspect that is overlooked in the EA paper is that the existing Regional Co-incident Peak Demand (RCPD) approach to interconnection under the TPM acts as a locational signal. Plus RCPD is clearly a strong signal for the exacerbating effect of higher peak load. TPAG's recommendations were that Transpower was well placed to consider any fine tuning of this mechanism.

MRP agrees with the observation in the TPAG final report that options like 'but for' are substantially more complex than status quo options such as RCPD which has been demonstrated to be simple and workable. We consider that the same arguments are likely to apply to the exacerbator pays approach and therefore support the consideration of modifications to existing mechanisms such as the RCPD and transmission alternatives regime as stable, predictable and low cost options to increasing locational price signals.

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

As above, MRP considers the application of exacerbator pays represents a theoretical locational pricing approach that is:

a) On the basis of significant previous analysis, not likely to result in material benefits;
b) Open to significant issues around exacerbator identification and therefore creates incentives to dispute cost allocations; and
c) Likely more costly to implement than incremental revisions to the status quo.

A number of alternative options are highlighted in Table 3 of the paper that could be considered as pricing methodologies under an exacerbator pays model. As noted in response to the previous question, we support investigation into the modification of the existing RCPD mechanism as an appropriate locational signal. We have previously offered support for TPAG recommendations around the KVAr charge which the paper notes which can act as an exacerbator signal for parties drawing reactive power.

We question some of the analysis presented in this section, particularly with regard to some of the specific comments made in section 4.5.22. In particular, it is stated that a LRMC-based price should provide efficient prices signals irrespective of the number users and as such a price allocation methodology is not necessary. The current HAMI price structure used for HVDC pricing is an LRMC-based charge and significant inefficiencies were noted by TPAG, particularly around generators offering peaking capacity[6]. This has potentially significant impacts on energy prices and also impacts on competition and hence energy consumers.

Finally, we support the intent in this section for the EA to assess the options according to the extent to which they promote the efficient use of the transmission network and efficient investment in the grid, generation, demand management and industry as a whole. We note that all of the options highlighted in the table have been considered by successive reviews and encourage the Authority to use this analysis as the basis for its assessment.

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

The paper raises questions around the incentives that might be created for potential exacerbators to act inefficiently to avoid any charges. It is suggested that a mechanism such as the current Prudent Discount Policy (PDP) could be employed to avoid the promotion of such behaviour.

MRP fully supports the intent of the PDP as established in the Code, specifically that:

> "the transmission pricing methodology does not provide incentives for the uneconomic bypass of existing grid assets."

We have concerns that the way the above objective is being interpreted in practice is not consistent with the intent. In particular, our concern relates to the fact that under a strict interpretation, the current PDP simply ensures that a particular set of outcomes - ones that we would view as commercially irrational anyway - do not occur. It does not remove the incentives for more rational grid bypass alternatives, which would still be inefficient from a national benefit perspective.

We consider the objective of the PDP should remain as above but the way the PDP is being interpreted warrants further review. However, we would advocate this occurs as a separate process to the TPM, potentially during the Transpower consultation on the new TPM once this review is completed, to ensure the issues are given sufficient consideration and emphasis.

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[6] TPAG final report pg 48 section 5.3

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

MRP agrees with the concept that where beneficiaries can be efficiently and reliably identified then they should be charged for the benefits received. This is likely to be relatively uncontroversial at the fringes of the grid where beneficiaries can be more easily identified but, in our view, extremely difficult - if not impossible - for assets like the HVDC.

TPAG considered the application of a beneficiary pays approach in depth and concluded that while it attributing costs to beneficiaries should be a supported principle, in practice it gives rise to a number of issues that need careful consideration around[7]:

- Identification of beneficiaries (see further comments below);
- Risks from over or under-allocating costs to beneficiaries;
- Alignment between decision-rights and allocation of costs;
- Allocating sunk costs versus new investments;
- Free-riding; and
- Potential distortions for efficient operation and investment

MRP considers that these issues should be considered as part of the EA review in understanding the practical issues around applying a beneficiary pays approach.

In terms of the specific mechanism for identifying beneficiaries, the paper proposes three options:

1. Indentifying users as a proxy (e.g. flow tracing)
2. 'What if' analyses (comparisons of volume/price benefits with and without investments)
3. Ex-ante identification (e.g. as part of the GIT approvals process)

<u>Users as Proxy</u>

The view from TPAG was that flow tracing had been proven as a generally workable approach to identify use of the network. However, taking users as a proxy should be implemented with care. While the decision to use the network is arguably voluntary, the actual pattern of use is dictated by the underlying physics of the network rather than user choice or private benefit. Without the ability to exercise a property right over the use of the network, the benefits to a network user may be less than implied under a simply users-as-proxy approach.

[7] TPAG final report pgs 35-36 section 4.5.8

What if

In relation to the HVDC, the paper suggests a General Equilibrium Model analysis could be undertaken based on a 'No HVDC' counterfactual or treating the link as a quota restriction on trade in electricity between the North and South Islands.

As is discussed in further detail in the ex-ante section below, theoretically removing the HVDC then attempting to identify and quantify the beneficiaries is a process that is likely to be fraught with significant and potentially insurmountable challenges. Given the beneficiaries of the HVDC link are variable and dynamic, any analysis will, by its nature, have to be highly assumption driven. It is therefore likely to be too subjective and open to challenge to form the basis of a durable pricing approach.

Ex Ante

The paper indicates that qualitative discussions by TPAG and as part of the Electricity Industry Transmission Pricing Project as well as the mini-grid investment test at the time of HVDC upgrade could be used to make an assessment as to beneficiaries.

The TPAG process highlighted clearly and robustly the substantial challenges in undertaking this type of analysis. Specifically it noted the HVDC link provides a mix of benefits which vary across time and circumstance. The report considers the HVDC primarily benefits[8]:

a) SI generators and/or NI customers in very wet periods;
b) SI customers and/or NI generators in dry periods;
c) NI customers and/or SI generators in peak demand, low wind or thermal plant outage periods; and
d) NI generators and/or SI customers in very windy periods when demand is low and thermal units are backed down to minimum.

In addition, the size of these benefits varies according to a range of factors such as the relative prices in each island, capital costs, exchange rates, fuel supply, technology costs and carbon prices to name but a small set of the issues that were considered by TPAG.

The Mini-GIT analysis of the HVDC mentioned is useful in characterising and quantifying the nature of the broad benefits from the HVDC, however it would be difficult to attribute costs at a more granular level. None-the-less, it would be difficult to conclude from the analysis that South Island generators are the sole beneficiaries of the HVDC.

[8] TPAG final report, pg 69 section 5.10.9

While qualitative assessments can be useful in the identification of beneficiaries the analysis shows how difficult and debateable this process can be in practice. By their nature, beneficiary assessments are static and require sensitivities around how beneficiaries might change over time (which is subject not only to commercial drivers but also government policy) and which is therefore inherently subjective. This suggests a beneficiary pays approach, while useful at some levels, will likely have limited application in resolving long standing debates around issues such as HVDC cost allocation.

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

The paper states that to avoid creating inefficiencies, the charge that applies to beneficiaries should reflect the lesser of the charge which will fully recover the costs of the grid being paid by beneficiaries and the anticipated value to them from the services provided by the grid. Effectively, beneficiaries should not pay more than their private benefit.

MRP considers this an appropriate application and notes it is unlikely the current charging regime for the HVDC allocates costs to South Island generators consistent with their private benefit.

As with the exacerbator pays approach, we have concerns that the paper considers there may be merit in implementing a beneficiary pay approach *ex post* on the basis that allocation of sunk costs provides more certain information on the benefits to particular parties and sends a signal to future investment. We consider the same arguments in relation to *ex post* application of exacerbators pays outlined in question 7 and 8 apply here as well.

While the paper notes that that TPAG was unable to reach consensus as to whether the beneficiaries of the HVDC link could be reliably identified, we consider the robust and exhaustive analysis provided by TPAG clearly illustrates the uncertainties and inherent subjective nature around beneficiary identification of Pole Three. We have concerns that claims that beneficiaries can be reliably identified are ideologically driven rather than logical conclusions that follow from the facts. While TPAG was unable to reach a conclusion on this issue for this reason, it did make clear recommendations to the EA which are discussed in response to Question 15 below.

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

Prima facie, any increases in costs will result in incentives for any entity to consider whether the private benefit of grid connection exceeds the costs. However, this analysis would rationally encompass of a range of costs and benefits not considered at all in the paper.

In undertaking the decision to disconnect the "disconnector" would have to weigh the cost of increased transmission charges against the additional costs it would incur and from disconnection and the benefits provided by grid connection. As a starting point some of the costs that might be incurred are outlined in Table 1 below.

Table 1: Potential costs incurred by a grid disconnector

Logistical	Acquiring land, transporting and installing back-up generation
Regulatory	Obtaining resource consents and managing compliance
Fuel related	Negotiating fuel supply contracts and providing adequate storage
Operational	Staff requirements and costs from ongoing plant monitoring and maintenance
Infrastructure	Additional electrical supply equipment and potentially fuel supply
Ancillary	Frequency and voltage support normally provided by grid

In addition to the above costs, the disconnector would also find itself exposed to having to manage a number of risks that could potentially increase its costs over time. For example: the risk that fuel costs increase or unplanned outages affect production. Managing these costs and risks are not likely to be core business to the disconnector but are for the energy supply industry.

By virtue of large economies of scale the industry is also likely to be able to provide lower cost supply than the disconnector which can also be fixed via long term contracting. Transmission charges to a large extent are fixed with any increases generally signalled in advance. As such it does not appear rational that a large direct connect would effectively seek to substitute what are largely known fixed costs for a number of potentially variable costs and risks which it may not be well placed to manage.

With a grid connection, marginal increases in energy demand to increase production output can be easily accommodated and allow greater flexibility in how production capacity can be operated and potentially expanded. In comparison, with self generation, any increases in demand would require generation expansions that tend to be lumpy in nature, as well as requiring sufficient back-up resources.

Not only would this approach be very capital intensive, it also runs the risk that the assets acquired are not the 'right size' and significant excess capacity is installed. Without a grid connection the disconnector would not even have the option to export this excess capacity to capture some of this lost value.

As a result a grid connection is likely to be more efficient for a large user in the longer term. It also provides a high degree of reliability and security when compared with own generation in the sense that it is only economic for the disconnector to build in a certain level of redundancy.

Appendix B

In terms of the analysis provided in Appendix B, MRP considers that it is highly dubious to base the cost assessment on a single transaction. The Whirinaki assets were developed in the context of the Government's reserve energy scheme. In our view, this investment would not have been committed if assessed on purely commercial grounds.

As a result of the location and fuel type as well as caveats around how the plant should be operated, the Whirinaki assets were traded at a substantial discount of around a fifth of their original value. This undoubtedly skews the analysis provided in the paper and we consider that without reference to more than one transaction, the figures provided cannot be considered robust by any objective measure.

In addition, the Whirinaki transaction at 155MW is substantially larger capacity than would be needed by almost any large industrial user in New Zealand. The salient point here is that it will most likely be more cost effective on a per KW basis to purchase larger than smaller generation units of a same type. As a result any disconnector seeking to acquire generation units would likely do so at a premium to the figures presented.

The analysis also does not include consideration of the costs a disconnector would be likely to incur by having to run its own generation to meet 100% of its own demand. The paper considers that in this situation the disconnector would need to acquire new back-up generation. However, the EA base the back-up generation utilisation rates (1% and 3%) on figures derived as if the user still had a direct grid connection. Such utilisation rates are unlikely in practice given the likelihood of unplanned outages and ongoing maintenance. The results therefore are likely to be highly sensitive to increased utilisation rates.

As a result of the above, MRP does not consider it credible that increasing transmission costs would lead to realistic incentives for grid disconnection.

Materiality of Grid Disconnection

The EA uses MED figures to indicate that in 2010, 37.7% of electricity consumption was by industrial users and that 9.9% of electricity occurred in cogeneration plants. We note that not all industrial users have co-generation facilities, using the same MED data, co-generation plants represent only 571MW or 6% of the total national installed capacity. Large users without co-generation facilities would face substantially larger costs to disconnect from the grid as they would have to acquire sufficient generation capacity to cover peak usage and also back-up generation.

In addition, of the currently installed co-generation plants, around 40% operate on fuel sources other than gas. As gas is likely to be the most economic fuel source for back-up generation, those co-generation facilities without access to gas supply, or only limited access, will face additional infrastructure costs to increase supply. Ruling out such facilities as candidates for disconnection suggests that theoretically the disconnection risk would be more likely to be around 3.6% of total national installed capacity. However, given this analysis doesn't take into account the other costs and benefits presented above, in MRPs view and on any rational basis, we consider the actual risk to be immaterial.

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

As highlighted throughout this response, MRP is supportive of the transitional postage stamp pricing option identified during the TPAG process in relation to the HVDC assets. Our view is that this option will deliver dynamic efficiency gains by enhancing competition in the market while at the same time addressing wealth transfer issues through the transition regime.

Contrary to the emphasis in the consultation paper, there was a high level of agreement during TPAG that HVDC pricing leads to the following inefficiencies:

a) **Possible generation investment inefficiency from delaying SI generation:** The HVDC charge leads to a disincentive for investment in SI generation relative to NI generation as the HVDC charge adds around 10% to the total cost of a new SI project. This disincentive would lead to generation investment inefficiency if SI generation investments are delayed relative to otherwise equivalent NI options .

b) **Competition effects between SI generators resulting from the HVDC charge**: The allocation mechanism for the HVDC costs would favour new generation investment in the SI by large incumbent SI generators relative to small incumbent generators or new entrants if those new investments by the large incumbent are more likely to delay alternative NI rather than SI investments by competitors. If this occurs it would lead to large incumbent SI generators increasing their dominance in the SI with a consequential reduction in competition in generation and retail, and potential inefficiency.

c) **Generation investment and dispatch inefficiencies from the HAMI price structure:** The HAMI allocation provides disincentives to generators to offer peak capacity and to invest in or maintain peaking generation capacity.

TPAG was unable to obtain consensus was around the magnitude of associated efficiency losses. However, specific recommendations were made by TPAG in terms of resolving the apparent impasse. TPAG recommended that the EA undertake further GEM analysis to verify the size of the efficiency loses and on that basis take a decision between the transitional postage stamp and the status quo.

MRP considers this should be the preferred option on the basis that:

a) HVDC pricing remains the most controversial and unresolved aspect of the TPM;
b) It would avoid the need for the EA to undertake further analysis to reach similar conclusion to previous reviews; and
c) Would provide certainty either way.

From MRP's perspective the current regulatory uncertainty created from continuous reviews of the TPM is creating issues in terms of the current valuation process it is undertaking as part of the Mixed-Ownership Model.

We appreciate the EA's need to ensure it establishes a consultation process that is robust, but we consider that issues such as transmission pricing that result in significant wealth transfers are always going to create incentives for dispute. In this regard we consider it unlikely that a consensus view is achievable and that the TPAG recommendation represents the most efficient course of action at this stage.

In terms, of the incentive free allocation to South Island generation , MRP agrees with the analysis in TPAG that this mechanism, given that it effectively arbitrarily allocates costs to a sub-group of participants is likely to be immediately controversial. It would also not be consistent with the allocation of other costs and retain the distinction between AC and DC assets that we consider is not warranted. On this basis, we do not support the incentive free allocation over the postage stamp transition.