meridian

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Submissions
Electricity Authority
By email: submissions@ea.govt.nz

Transmission Pricing Methodology Review: Beneficiaries-pay options

Meridian welcomes the opportunity to provide feedback on the Electricity Authority's working paper "Beneficiaries-pay options" dated 21 January 2014.

For the reasons set out in our submission on the October 2012 Issues Paper (1 March 2013), Meridian:

- agrees that the present transmission pricing methodology (TPM) can be improved upon, including by removing the arbitrary and inefficient distinction between HVDC and HVAC assets and by creating price signals which will promote dynamic efficiency gains in relation to transmission, generation and load;
- considers that an SPD-based approach for determining beneficiaries is a constructive and durable approach;
- recognises that, while there is no perfect TPM (in particular, trade-offs need to be made to achieve the dynamic efficiency gains while minimising any static efficiency detriments), improvements can certainly be made on the status quo; and
- supports an approach which is predictable and less complex in order to minimise barriers to entry for new market participants.

Given that the options discussed in the working paper are not exhaustive and given the potential interdependence of various aspects of the TPM (including how residuals are allocated), this submission does not attempt to comprehensively assess each option or to compare the options in detail. However, Meridian notes that:

- Each option is likely to be superior to the status quo because of the potential dynamic efficiency gains in terms of future decision-making and durability of the methodology.

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- The zonal approach seems the least desirable because it involves contentious design choices, mutes pricing signals and reproduces one of the key problems identified in relation to the current TPM namely that where the cost of an investment falls only on a subset of the beneficiaries, the payers may be incentivised to oppose or delay the investment. This would negatively affect its durability.

The remainder of this submission discusses each of the options in turn and contains Meridian's comments on particular aspects.

SIMPLIFIED SPD CHARGE

For the reasons set out in our submission on the October 2012 Issues Paper which included our own simplified SPD proposal (Meridian's March 2013 proposal), Meridian supports simplifying the original SPD model in order to make the charges easier to understand and predict, and to reduce short term volatility in overall transmission charges.

Assets to include

The Authority proposes including the following assets: (i) Pole 2; (ii) investments added to Transpower's regulatory asset base after 28 May 2004 but before 10 October 2012 with a cost greater than $50m; and (iii) investments added to Transpower's regulatory asset base from 10 October 2012 with a cost greater than $20m.

Meridian recognises that the choice of assets is inevitably a pragmatic balance of being more comprehensive versus increasing complexity.

Meridian notes that the proposal is in line with Meridian's March 2013 proposal and supports it.

Capping

Meridian agrees that capping is appropriate and that choosing the appropriate capping time frame requires a pragmatic trade-off.

In our March 2013 proposal, we proposed a capping period greater than half an hour, such as weekly or monthly capping.

Meridian does not have a strong in principle view as between daily, weekly or monthly capping, but notes that a longer period may reduce the risk that the SPD-charge understates the true benefits from a transmission asset over the course of a year (and over the asset's lifetime).

Gross versus net benefits

Meridian agrees with the Authority's preference for gross benefits over net benefits with refund (NBR), and NBR over net benefits only (NBO).

In addition to the reasons referred to by the Authority, Meridian considers that gross benefits will create more appropriate incentives than NBR in relation to dynamic efficiency.

The following table compares gross benefits and NBR in terms of the effects in relation to investment in generation, load and transmission:

	NBR versus gross benefits: Dynamic efficiency implications
Generation investment	Transmission investment will create disbenefits to generators where higher cost generation sells less or sells at lower prices because a constraint has been removed. Meridian's first comment is that these sorts of losses occur all the time in markets and without compensation being payable. To use a spinach example, if a new road allows cheaper (more efficiently produced) spinach access to a market, compensation would not be payable to the displaced less efficient spinach growers by the entity that constructed the road. The NBR approach would turn the right to enjoy a transmission constraint into a compensable property right. One of the key purposes of the grid is to avoid fragmentation and allow for the operation of a national electricity market. In Meridian's view, generators can, and should, assume the risk of constraints being removed by new transmission investments. Secondly, if new generators receive disbenefit payments (ie because they locate in an area that used to have higher prices before a transmission constraint was removed), then generation investment decisions will be based on a historical grid configuration not on the current or potential future grid. To use the spinach analogy, it is appropriate for a new spinach farm to make location decisions based on the new road and not to receive a compensation payment if it locates in the area that was previously protected from competition Accordingly, gross benefit is preferable from a dynamic efficiency perspective in terms of generation.
Load investment	Meridian notes that a transmission investment should generally reduce prices and improve reliability and therefore disbenefit to load may not be common. As with generation, this sort of loss does not usually attract compensation (e.g., a restaurant is not compensated because a new bypass road reduces passing traffic). A gross benefit approach is also preferable from an efficiency perspective as load investment decisions should be based on the current grid rather than the virtual historic grid implied by disbenefit payments.

Transmission investment	In terms of scrutiny of and lobbying for transmission proposals, we see some benefits in an NBR approach. That is, without compensation for disbenefits a generator (or load) may oppose an efficient transmission investment because it will leave them worse off. However, it seems that such a motivation should be transparent and therefore unlikely to inappropriately influence decision-making. Importantly, the parties affected by the charge would be engaged in the process.

Accordingly, Meridian considers that gross benefit is the appropriate principle.

Basis for charge: Ex ante, annual and three year rolling average

Meridian's March 2013 proposal included an annual ex ante charge. The Authority proposes a similar charge, but with a three year rolling average.

Meridian considers that having a two or three year rolling average will desirably smooth fluctuations in the charge while allowing longer term trends to be reflected.

The proposed charging mechanism will improve certainty and reduce volatility for participants. It is unlikely that the proposed mechanism would produce charges that were more volatile than the current regime for interconnection charges.

Meridian notes that there are a number of second order implementation issues that the Authority will need to consider:

- Commencement of the regime: For year 1, what data will be used to determine the annual charge?

- Entry/exit: Where a participant enters or exits the market, how will charges be calculated and/or adjusted?

- Transfer of assets: What mechanisms need to be in place to deal with asset transfers? Presumably where an asset (such as generation plant) is transferred, the SPD-calculated benefit over the last three years should be applied in relation to the new owner?

Demand response and assumed costs of non-supply

The Authority proposes that:

- Dispatchable demand bids would be used for calculation of the SPD charge, provided dispatchable demand is dispatched. For other demand not subject to dispatchable demand, the SPD charge would be calculated using a demand elasticity based on empirical estimation.

- The price for non-supply that should apply should reflect the incidence of non-supply in the absence of the investment. Of the 10 investments modelled in the working paper, this would mean a price for non-supply of $3000/MWh, except for Pole 2, which would have a price for non-supply of $1000/MWh.

Meridian considers that the Authority's approach to demand response and assumed costs of non-supply is appropriate. It will need to be re-applied from time-to-time as the incidence of non-supply in the absence of a particular asset will change over time.

Distributed and load-specific generation

The Authority proposes that:

- SPD charges for distributed generation would be calculated on the basis of net injection to the grid.
- SPD charges would be calculated at substation level at locations where grid-connected generation has been installed to supply a specific load at a separate node at the same location.

As Meridian has previously submitted, embedded generators should be subject to the SPD-calculated benefit charge and the residual charge (subject to a de minimus threshold).

Meridian agrees that it is a more complicated matter as to whether this is based on net or gross generation: net may understate benefits of the grid and encourage embedding, while gross may overstate benefits received.

Meridian does not consider that either is clearly preferable in principle and that Authority should be guided by a cost-benefit analysis and administrative factors.

10MW de minimus threshold

The Authority proposes that the minimum threshold for the SPD charge would be 10MW by scheme. Meridian supports the proposal as a sensible cut-off level, subject to formalising the definition of "scheme".

Instantaneous Reserves

The Authority proposes that providers of instantaneous reserves should be included in the calculation of the SPD charge.

Meridian agrees with the proposal, but submits that the charge should be on a gross rather than NBR basis for the reasons set out above.

Parties

The Authority proposes that the SPD-calculated benefit charge be levied on:

- 29.1. generators;
- 29.2. direct connect users; and

- 29.3. retailers (rather than distributors).

It terms of the choice between retailers and distributors, Meridian considers that it is preferable that distributors (rather than retailers) are the counter-party on behalf of general load for a number of inter-linked reasons. While Meridian agrees with the Authority's focus on dynamic efficiency and, of particular relevance here, incentives to scrutinise transmission investment proposals, it considers that there are other factors to take into account here.

First, Meridian considers that imposing the charge on retailers rather than distributors would create extra costs and complexities. As set out in our submission on the October 2012 Issues Paper (1 March 2013), [193]-[197]:

- Distributors are the only parties with the information and operational capabilities to respond to peak demand signals by managing load within a region.

- Having retailers as customers under the TPM would increase the number of contract counterparties for Transpower.

- Having retailers as customers would require a new set of arrangements for dealing with ACOT issues for distributed generation.

- Prudential requirements would change especially as retailers are likely to have a higher default risk.

Furthermore, if the charge is levied on retailers, it will have to accommodate entry/exit and changing market shares.

Secondly, Meridian is concerned that the complexities set out above together with the financial risk for retailers of mis-estimating transmission charges, could create a material barrier to entry in the retail market. It may be helpful for the Authority to canvas recent and potential new entrants in this regard.

Thirdly, also in relation to retail competition, Meridian considers that it is important that transmission and distribution charges are as transparent as possible so that consumers can most easily compare retail electricity prices and identify the best offer for their circumstances. In our view, it will be clearer for consumers if transmission charges (which will not be a point of difference between competing retailers) are passed on via distribution companies as they are now, rather than being part of the retail price package. Introducing extra complexity into consumer decisions would be a step in the wrong direction.

Finally, in terms of scrutiny of transmission investments, we consider that the airport/airlines analogy is of little assistance because of a number of structural distinctions. In particular:

- In contrast to airlines/airports, whether or not electricity retailers play a role, transmission investments will be scrutinised by generators, direct connect customers, consumer groups and at least some distributors (e.g., where there is consumer trust ownership). That is, transmission assets will have a broader charging base with a diversity of interested parties compared with airlines/airports.

- Airlines take a greater collective interest in airport charges than retailers would in relation to transmission charges because of the greater threat of inter-modal competition for travel.

- Landing charges are not simply a “wash” for airlines. Given choices about routes and capacity, the level and structure of landing charges can have a direct impact on airline profits. In contrast, transmission charges will be competitively neutral as between retailers.

Overall, Meridian considers that it is clearly preferable for the load charge to fall on distributors rather than retailers.

GIT-PLUS-SPD AND SPD-PLUS-GIT CHARGES

Meridian generally supports the idea of recovering some or all of the revenue requirement for reliability investments through an administratively allocated GIT charge, particularly where such amounts would otherwise be recovered through the residual charge. The GIT based payment for a reliability investment can be seen as analogous to an insurance premium.

In order to allow charges to reflect changing use patterns over time, Meridian agrees with the Authority’s preference for SPD-plus-GIT over GIT-plus-SPD. That is, to the extent that a reliability investment produces SPD-calculated economic benefits these charges should take priority. Meridian notes that transmission investments may become more economic-focussed and less reliability-focussed over time.

In terms of the implementation of a GIT-based charge, Meridian considers that further work is required in terms of the how the beneficiaries of a reliability investment are identified. That is, whether or not a group is identified as the primary beneficiary or an ancillary beneficiary of a reliability investment will have significant consequences.

ZONAL PRICING

Meridian considers that zonal pricing is likely to be inferior to the other beneficiaries-pay models being considered by the Commission.

In particular, Meridian agrees with the Authority’s concerns that zonal pricing would:

- require lots of contentious design issues to be resolved; and
- produce price signals that were muted compared with the other beneficiaries-pay models.

Meridian also submits that the methodology by artificially limiting the deemed beneficiaries of an intra-zonal asset to the participants in that zone, zonal pricing will reproduce one of the problems with the current TPM. That is, as with HVDC investments today, if only a subset of the beneficiaries pay for it, the payers will be incentivised to oppose an investment (or at least support its deferral).

Meridian also doubts whether zonal pricing would in fact be simpler to understand or implement than the other models.

In terms of the contentious nature of the design issues, Meridian submits that:

- Dividing the transmission grid into appropriate zones would require very subjective judgment calls and be highly contentious.

- Furthermore, the appropriate zones and interconnectors would change over time as generation, load and transmission change over time. Accordingly, the zonal pricing model would likely result in ongoing decision-making and disputes in relation to design issues.

Please contact me if you have any questions regarding this submission.

Yours sincerely,

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