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Submissions
TPAG Chair
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TPAG Transmission Pricing Discussion Paper

The Transmission Pricing Advisory Group (TPAG) has reached an important milestone with the release of its consultation paper assessing options for:

- Allocation of HVDC costs
- Deeper or shallower connections or deeper allocation of connection costs to specific market participants; and
- Static Reactive compensation.

Meridian congratulates TPAG and its advisers for the comprehensive assessment framework it has developed to guide its analysis on these complex matters.

An effective transmission grid provides significant market and public benefits by enabling a more diverse and competitive generation market which underpins the efficient and secure supply of electricity to consumers. Meridian agrees with the TPAG that the costs of transmission should be allocated in a way that both encourages efficient use of the transmission network in real time and the efficient investment in new load and generation projects over the course of time.

New Zealand's energy sector is constantly evolving and has now reached a point where a significant number of transmission investments have already been approved and are in various stages of implementation. Future sources of generation are likely to include a number of renewable energy projects – geothermal, hydro and wind, each of which are highly locational specific. These factors mean that there are very few future opportunities to co-optimise transmission and generation investments and hence no value in adding additional locational signals to the existing HVAC interconnection charges.

This leaves the question of whether it is appropriate to continue with the existing locational signals provided by the allocation of HVDC charges to SI Generators. The functions that the interisland HVDC link performs have changed significantly over time. TPAG has acknowledged the role the HVDC link plays in wet and dry years transferring electricity between both islands as well as providing a number of critical interconnection benefits to the system as a whole. These interconnection benefits to all grid users are likely to be even greater with the new capacity and functionality offered by the pole 3 upgrade.

The updated modelling work overseen by TPAG has conservatively quantified the economic costs of the existing HVDC cost allocation methodology. TPAG's analysis demonstrates these charges are likely to result in the deferral of lower cost SI generation in favour of NI alternatives and likely to have adverse impacts both on competition between NI and SI generators, between new and incumbent SI generators and on dispatch efficiency.

Transpower's current pricing methodology, which includes the HVDC cost allocation, is a schedule to the Electricity Industry Participation Code and is therefore a regulated cost allocation arrangement. Meridian considers the Authority has an ongoing obligation to ensure this regulated methodology is fit-for purpose and consistent with the Authority's statutory objectives. TPAG has estimated that removing the HVDC charges will result in a clear and material efficiency gain of between $11 and $96 million. It follows that the Code should be amended to realise this gain.

A postage stamp pricing methodology will release these efficiency gains. This leaves the Authority with a second question, namely over what time period should a transition from the current arrangements occur? Meridian's operating costs would reduce if there was a shift to postage stamp pricing. However, Meridian would also receive lower wholesale revenues under postage stamp pricing due to the entry of additional SI generation from that likely under the current pricing methodology (which effectively places a penalty charge on SI generation).

More importantly, the Authority is tasked with seeking the outcome which best serves the long term interests of consumers. In this regard Meridian accepts that the Authority should seek to avoid abrupt transitions from the current pricing arrangements. Meridian has therefore supported the majority TPAG decision to recommend a transition to postage stamp pricing of the HVDC costs over a ten year time frame. This will enable end-users to offset higher transmission costs against the benefits of more efficient wholesale prices.

TPAG also examined whether there was benefit in changing the methodology used for connection charges. Meridian observes it is difficult to quantify the impact of improved beneficiary information in the timing of investments particularly in the light of the Commerce Commission's new investment processes. This means there must be an element of uncertainty about the benefits of moving from the status quo to deeper connection charges.

In relation to the third matter considered by TPAG, Meridian agrees that the Code should be amended to remove a power factor requirement which electricity distribution businesses (EDBs) cannot meet and Transpower cannot enforce. The proposed option of kvar charge in the Upper NI and Upper SI is a practicable solution as it will give EDBs a choice of how to improve power factor performance in their regions.

More detailed comments on TPAG's Consultation paper can be found in the appendix to this letter. Our organisation will continue to work with the Authority and its advisory group on this matter.

Yours faithfully

Tim Lusk
Chief Executive

Meridian submission to TPAG on Transmission pricing discussion paper

Part One: Need for additional locational signals in TPM

Q1. Do you agree with the TPAG's assessment that there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments decision? If not, please provide your reasons.

Meridian agrees with the TPAG that there is no need to augment existing locational signals by changes to transmission charges for interconnection, noting

- TPAG's assessment is based on extensive analysis overseen by the Commission and the Authority using the GEM model and
- The analysis undertaken by the CEO forum reached a similar conclusion.

The main drivers of this recent analysis are the fact that new sources of generation namely wind, geothermal and hydro generation are much more location specific and the fact that most of the significant transmission investments have already been made meaning there are very few economic transmission investments to co-optimise.

Part Two: Decision-making framework

Q2-3. Do you agree with the TPAG's assessment that the changes to the statutory framework during the course of the transmission pricing review project do not require the Commission's analysis and development of alternative TPMs to be reworked? . Do you agree with the TPAG's assessment that the options developed through stages 1 and 2 of the Review were developed in a manner consistent with the Authority's statutory objective?

Meridian does not believe there is any need to redo the analysis undertaken by the Commission and its advisors including its high level evaluation of various alternative TPM options. The analysis undertaken by the Commission in Stage 1 of the Transmission Pricing Review focussed on identifying current issues with TPM and possible options to address those issues based on efficient pricing criteria. In Stage 2 efficiency criteria was also used to assess the value of enhanced locational signals for economic transmission investment. These steps would also have been undertaken by the Authority under its decision-making framework had it been established when the Transmission Pricing Review commenced.

Q4. The TPAG efficiency considerations: Has the TPAG identified appropriate efficiency considerations to assess the costs and benefits of different options? If not what other efficiency considerations would be appropriate?

Meridian believes the efficiency considerations in Table 10 are a practical way to apply the concepts of dynamic, allocative and productive efficiency to the assessment of different options for transmission pricing.

Part Three: Assessing Options for HVDC Allocation

Q 5. Do you agree there was sufficient evidence of a clearly identified opportunity for an efficiency gain to warrant analysis of alternative options for the allocation of HVDC costs? In particularly do you agree with the assumptions and analysis contained in section 6.2 and *further elaborated in Appendix D? If you do not agree please set out your reasons for reaching an alternative conclusion.*

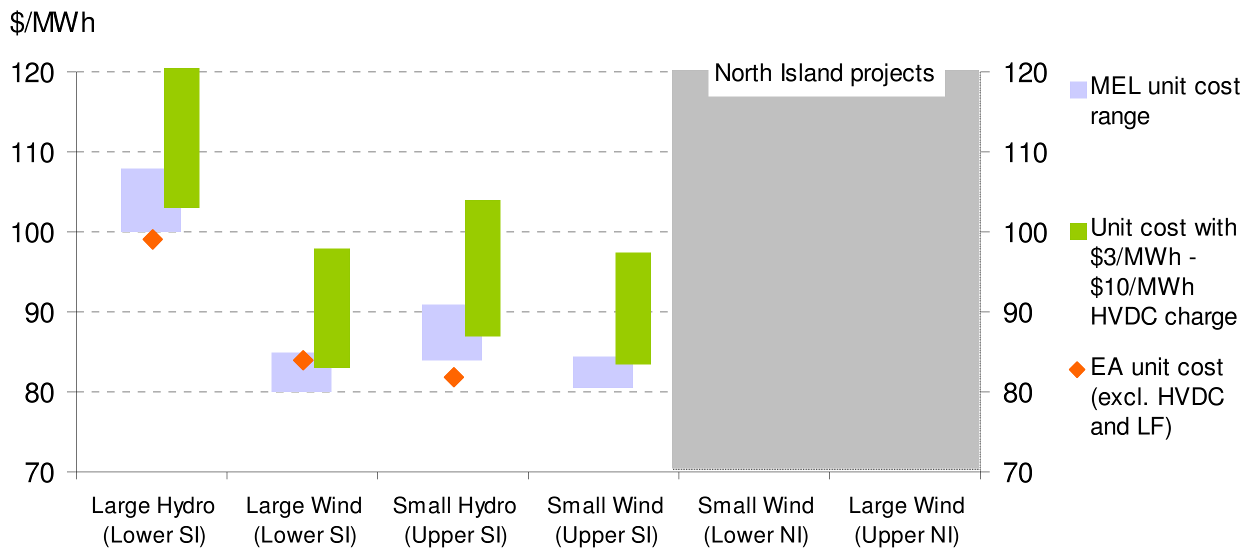
The analysis conducted by TPAG indicates that there is a clear and material cost associated with the current HVDC charge. An NPV over 30 years of 11-96m warrants analysis of alternative cost allocation options. By comparison Meridian notes the estimated NPV over 30 years of the locational risk proposal is between 38-77million.

Q6-7. Do you agree with the range of HVDC options identified for assessment? If not, why not? The TPAG has assessed the HVDC options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with and/or could provide further information on? Please provide details.

Meridian agrees with the assessment in Tables 26 and 27.

Q-8-9. What is your position on the two views? Do you have further evidence to support either the majority or minority view? Do you agree with the summary of the comparison of alternative options and the majority conclusion that leads to the identification of the postage stamp transition option as the preferred option? If not, please give reasons why.

The majority view is in essence that the current HVDC charge is material enough to change the NZ merit order of generation build resulting in generation inefficiencies which have been modelled conservatively between $19-96M. Meridian has recently completed a cost review of its pipeline of projects. Our analysis agrees with TPAG's unit cost modelling as contained in the simplified GEM style analysis. This is illustrated by the chart below which depicts Meridian's anticipated unit cost ranges for a selection of generation options in the North and South Islands.



Meridian therefore agrees with the majority TPAG view that postage stamp pricing over a ten year transition will remove the unintended generation inefficiencies from the current TPM and will result in a more durable arrangement for the future.

Q10. The TPAG's analysis assesses postage stamping the HVDC costs to offtake customers. In Table 17, the impact on the analysis of different postage stamp variants was considered. Do you think there are other variants of the postage stamp options that should be explored further? Please give reasons.

Meridian considers TPAG explored a representative range of variants to the postage stamp proposal.

Q11. If a transition to postage stamp option were recommended to the Authority and progressed further, do you agreed with the majority view that the $30/kW initial charge to existing grid-connected SI generators and 10 year transition period is appropriate? If not, please give reasons. Are there other issues with the transition to postage stamp options that should be considered? Please provide details.

Meridian understands the preference for a transition option. The proposed ten year transition should provide consumers with confidence that they will not face a step change in prices without having offset benefits of lower wholesale pricing.

Part Two: Assessing options for deeper or shallower connection

Q12. Do you agree with the TPAG's conclusion that any further analysis of deeper connection options requires close coordination with the Commerce Commission?

Meridian agrees that it is difficult to assess the benefits of deeper connection options without some experience of how the new transmission investment regulation, and in particular the arrangements for transmission alternatives, will work in practice.

Q13. The TPAG has made a broad estimate of the possible efficiency gains from deeper allocation of costs to specific participants of $15 to $40m NPV. What do you think is the likelihood that such efficiency gains might be possible? Please give reasons.

Meridian notes it is difficult to quantify the impact of improved beneficiary information on the timing of investments. This means there must be an element of uncertainty about these efficiency gains.

Q14-15. Do you agree with the range of options for deeper or shallower connection, or for deeper allocation of interconnection costs, that have been identified? If not, why not? The TPAG has assessed the 'but-for', flow trace and shallow connection options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details.

Meridian generally agrees with the range of options identified to address the connection-interconnection boundary and TPAG's assessment of these options against the efficiency considerations. Meridian notes the high potential for disputes with the "but/for" methodology and would be very concerned if this methodology led to delays in the implementation of reliability investments.

Q16. Do you think there is justification for the Authority to progress further analysis of connection options or a deeper allocation of costs to specific customers? If so, please give reasons.

Meridian is keen to understand how transmission alternatives will work in practice before there is any further work on alternative connection pricing options.

Part Three: Assessing options for Static Reactive Compensation (SRC)

Q17. Do you agree with the TPAG's overview of the background on SRC and the identification of the regulatory failure described in this section? If not, why not?

Meridian agrees that the current arrangements for SRC are not workable and that changes need to be made to the Connection Code to ensure that its better meets industry requirements.The key point is that the Connection Code is not fit for purpose as it is inefficient for Transpower to have multiple non-compliance arrangements which are problematic to enforce.

Q18. Do you agree with the selection of SRC options selected for assessment? If not, why not?

Meridian agrees price signals are required to enable EDBs to make efficient choices between investing in SRC equipment themselves, relying on Transpower to invest in grid SRC equipment, or "encouraging" their end-use customers to improve any poor power factor performance. The various SRC options assessed by the TPAG are an appropriate representation of the alternatives.

Q19. For option 4, the amended kvar charge, do you support the approach of retaining a minimum point of service power factor for the UNI and USI regions as a backstop measure? If so, do you support the recommended approach of providing a penalty rate for demand in excess of the minimum?

Meridian believes the kvar charge should address power factor issues.

Q20-21 . The TPAG has assessed the amended status quo and the amended kvar charge options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details. Do you *agree with the TPAG's summary of the costs and benefits of the options assessed and its observations? If not, why not?*

Meridian agrees with TPAG's assessment that Option 4 will best achieve the regulatory objective as it removes the problems of high transaction costs and holdout, gives off take customers a choice of options to improve poor power factor in their region and is likely to be durable over time. The only down side to this approach is the risk of stranded and duplicate investments. However this risk does not appear to be material compared to the overall benefits of the proposal.

Q22- 24. Do you think it appropriate that minimum power factor requirements are retained in the Connection Code for points of service in the LSI and LNI regions, when a view has been taken that such arrangements are unenforceable in the UNI and USI regions and thereby amount to a regulatory failure?. In your experience are there any other issues that arise from the current prescription within the Connection Code of minimum power factor for points of service in the LSI or LNI regions? Please provide background relevant to any issues you identify.. If you have identified issues in the previous question, do you think an approach similar to the amended kvar charge option, possibly incorporating a penalty charge for reactive power demand in excess of a set minimum power factor, would provide a better approach to address the issues you have identified? Are there other options that should be considered?

Meridian believes there should be consistency in the backstop arrangements across regions.

Q 25 Do you support the recommended introduction of an amended kvar charge (option 4) into the TPM? Please provide reasons.

Meridian believes the amended kvar charge is preferable to the status quo which is clearly unworkable from the perspective of both Transpower and the EDBs.

Part Four Indicative Draft Guidelines

Q26 . Bearing in mind the indicative Draft Guidelines are intended to reflect the TPAG conclusions set out in this Discussion Paper, do you have any alternative drafting suggestions?