Fonterra Co-operative Group Limited

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12 July 2011

Electricity Authority - Submissions
c/- Electricity Authority
TPAG Chair
PO Box 10041 Level 7
ASB Bank Tower
Wellington 6143

Attention: Dr Graham Scott

Dear Graham

RE: Fonterra Submission – Transmission Pricing Discussion Paper

Thank you for the opportunity to make a submission on the Transmission pricing discussion paper.

Our submission is presented in the same order as the Transmission Pricing Advisory Group (TPAG) discussion paper and we have attempted to answer each TPAG question.

Submission Summary

The most contentious issue of the Transmission Pricing Methodology (TPM) for Fonterra is the reallocation of the High Voltage Direct Current (HVDC) charges. We have serious concerns about the HVDC proposal and believe that the basis of the TPAG HVDC proposal is flawed. The TPAG HVDC proposal rests on the validity of the merit order that has been developed to show a possible pay back in avoided increase in wholesale energy costs though cheaper South Island Generation (SIG) being brought forward by removing the HVDC charge from SIG. We do not think that TPAG has adequately accounted for other project influences that would create some level of disorder in the TPAG merit order. TPAG has acknowledged in the discussion paper that the merit order does not model a number of external project influences. We have attempted to understand what level of disorder in the merit order is needed for the benefit to consumers to be lost. A number of credible alternative scenarios are considered by Fonterra using a simplified merit order model that show that some of these real world influences will remove all benefit to consumers that TPAG have proposed and that the effect of removing the HVDC charge from SIG is immaterial.

We submit that the status quo should be retained with HVDC charges.

We are disappointed that the High Voltage Alternating Current (HVAC) component of TPM has not come to a clear recommendation, but also understand TPAG's position that to progress with the development of AC methodologies, particularly exploring deeper connections for consumers, TPAG will need co-ordination with the Commerce Commission. We support the TPAG in continuing with this work but note that a lot of emphasis appears to have been placed on the HVDC charges and delivery of the Electricity Authority (EA) timeline at the expense of a complete TPM proposal.

We generally support TPAG's proposal for static reactive compensation and retaining a lower power factor limit for Lower South Island (LSI) and Lower North Island (LNI).

We generally accept the TPAG assessment that stage 1 and 2 of the TPM review, under the former Electricity Commission, was done largely in line with the EA statutory objective and there is little value in revisiting stage 1 and 2 analysis.

We agree with TAPG that there is limited or no value in additional locational price signalling.

Finally, if the HVDC charges are reallocated, we would encourage the EA and TPAG to monitor the avoided increase in energy costs and report to participants the soundness of the decision. However we don't believe that this can be done. If it were possible to record this we believe TPAG the EA or industry participants would measure the effect of the current methodology now and present the information as evidence in support of or opposing the reallocation of HVDC charges. We don't see this evidence being presented. This leads us to the very uncomfortable position of being asked to fund a proposed change in TPM that has very uncertain benefits and no method of measuring whether any of the benefits were realised.

I trust the information contained here adequately details our response to the TPAG Transmission pricing discussion paper. We welcome any opportunity to comment further as TPAG and the EA continue with this work stream, in particular we would like the opportunity to make cross submissions post TPAG's assessment of this discussion papers submissions.

Thank you once again for the opportunity to make this submission.

Yours sincerely

Greg Walsh

General Manager NZ Quality Assurance and Technical Services

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Fonterra
Dairy for life

4 August 2011

Electricity Authority - Submissions
c/- Electricity Authority
TPAG Chair
PO Box 10041 Level 7,
ASB Bank Tower
Wellington 6143

Attention: Dr Graham Scott

Dear Graham

RE: Fonterra Submission Alteration– Transmission Pricing Discussion Paper

I would like to make a change to the Fonterra submission please.

Two scenarios, and references to them, were included under Question 5 (HVDC) that I would like to remove. These two scenarios show that the removal of one major generation project would result in a negative NPV for consumers. This negative NPV is accurate only when the projects are removed from the no HVDC charge stack and left in the base case stack. It is implausible that removal of the HVDC charge would influence such an outcome. In our modelling we should have removed the project from both stacks. This was an oversight and these two scenarios should not have been included in our submission in this form.

If you are agreeable please remove and replace page 4 with the new attached page 4. I have shown the items to be removed as struck out, the pages are otherwise identical.

In all other respects our submission remains the same.

Apologies for any confusion this may cause, I wish to make this change as early as possible to avoid any unnecessary work by the members of TPAG.

Do not hesitate to contact me should you wish for any clarification.

Yours sincerely

Glenn Sullivan

Group Manager – Electrical Engineering

glenn.sullivan2@fonterra.com

CC Greg Walsh
Fonterra General Manager NZ Quality Assurance and Technical Services

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.

Yes we agree with the TPAG assessment that there does not appear to be an economic benefit from enhanced locational signalling.

Q2. 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?

We agree that there appears to be a strong economic basis of analysis of the stages 1 and 2 that aligns with the new EA statutory requirement. On this basis we generally accept that the former Electricity Commissions development of the alternative TPM's does not to be reworked.

Q3. 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?

As per Question 2 above we generally accept that the options developed through stages 1 and 2 are consistent with the EA's statutory objective.

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?

We generally agree with the efficiency considerations that TPAG have identified.

HVDC

Q5. 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 particular 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.

There appears to be a prima facie case that warrants further analysis of a potential efficiency gain, however we do not agree with the assumptions and analysis contained in the discussion paper.

Firstly the analysis of the merit order, from which the conclusions have been drawn by TPAG, is incomplete. ~~The TPAG merit order appears to always show a positive NPV for a range of sensitivities. But~~ the model does not account for external project issues which have a material effect on the merit order[1]. ~~At some degree of disorder in the merit order the NPV will no longer be positive.~~ To understand this we have developed our own simplified merit order following the same principles as outlined in the TPAG Transmission pricing discussion paper Appendix D. We have aimed to emulate the TPAG merit order as closely as possible, but have not undertaken the range of sensitivity analysis completed by TPAG.[2]

Like the TPAG merit order, it is not imperative to have the Fonterra merit order exactly right to understand the effect of alternative scenarios.

What we found is that under various credible alternative scenarios the reordered merit order quickly approaches zero NPV ~~and can easily become negative~~. As shown in table 1 the effect of disorder on the merit order is material and needs to be considered by TPAG.

The influence of reallocating the HVDC charge on the merit order is largely immaterial when considered with all of the other possible influences. ~~E.g The removal of a single project can undo all of the HVDC reallocation benefits.~~

Table 1

	Project Description	Diff. NPV
1	Status Quo (base case)	$0
2	Remove HVDC charge from SIG	$140.9M
3	Clutha River Tuapeka occurs ahead of Generic NI Geo (i.e. one set of adjacent projects in stack swap order)	$108.9M
4	Three sets of adjacent projects swap order in the stack	$24.8M
~~5~~	~~One major generation project does not proceed. Eg Rotokawa2, Tuapeka, Tauhara2,.... (greater than 800GWhrs)~~	~~$119.1 to -$168M~~
~~6~~	~~One early project does not proceed. Eg South Island Peak Hydro (i.e. removed from stack)~~	~~-$204.72M~~

(Scenarios 3 to 6 with HVDC charges removed)

[1] Section 6.2.16 of the TPAG Transmission pricing discussion paper acknowledges these shortcomings of the merit order analysis.

[2] Refer to this submission Appendix A for Fonterra merit order analysis

At a minimum we believe that TPAG need to complete an assessment that determines how much disorder in the TPAG merit order is required for the benefit of reallocating HVDC to be lost, and then decide how likely this reordering of the merit order could be.

Given the merit order developed from the Statement of Opportunities has 82 projects in it we think that some level of reordering is inevitable and that the likelihood of HVDC charges alone influencing the merit order to achieve a positive NPV is very unlikely .

Our model shows annual electricity costs for New Zealand being approx $2.69B through $6.54B over 30 years (NPV $39.11Billion). The NPV value derived by TPAG $11M – $96M equals 0.0281% and 0.2454% of total electricity costs over the same period.

We do not accept that TPAG have shown a clear long term benefit for New Zealand consumers. Given TPAG's own observation that the effect of project influences identified in section 6.2.16 of the TPAG Discussion paper (but not modelled) would only need to vary the model by approx 0.023% to 0.25%, and that we observe real life examples of such influence now[3], it seems extraordinarily unlikely that TPAGs merit order will result in the outcome they have proposed.

Therefore we do not agree with the TPAG majority view that the HVDC charge should be transitioned to consumers and we submit that the status quo should be maintained instead.

Q6. Do you agree with the range of HVDC options identified for assessment? If not, why not?

Notwithstanding our position detailed in Question 5 the range of HVDC options identified for assessment is appropriate. One option we would like TPAG to also consider is flow trace for HVDC should;

- The AC shallow / deep recommendation be to adopt flow tracing.
- HVDC charges be reallocated to consumers.

i.e. roll the HVDC charges into a wider interconnection grid that is allocated on a flow trace methodology.

Q7. 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.

Postage stamp transition. Wealth Transfers and step changes in prices. As per Question 5 above we do not accept that the postage stamp transition proposal will result in net price rises to end-use consumers

[3] **Project Hayes** - Resource consents were granted by both councils [Original resource consent application made 2006 – comment by author] but those decisions were appealed to the Environment Court. The Environment Court Hearing commenced in May 2008 and after three adjournments the hearing closed in February 2009.The Environment Court declined consent in November 2009 and Meridian then appealed the decision to the High Court on points of law. In August 2010 the High Court upheld Meridian's appeal. In September 2010 an application to appeal the High Court decision was lodged and subsequently withdrawn in March 2011. The project now reverts back to the Environment Court to re-hear the appeals in light of the directions issued by the High Court. *Source – Meridian Energy Website.* *http://www.meridianenergy.co.nz/our-projects/south-island/project-hayes-wind-farm/*

Project Aqua - A number of uncertainties led to the decision to withdraw from Project Aqua and these were widely publicised at the time. Concerns about the nature of existing and likely future water rights and increasing delays in resolving Aqua's consent process and likely outcomes were central to the decision. *Source – Meridian Annual Report 2004* to less than 1%. Under any number of credible alternative scenarios net price rises to end-use consumers will be much higher than 1%. The transition arrangement only guarantees a transfer of costs from the South Island generators to end consumers and provides very uncertain potential benefit to consumers.

Q8. What is your position on the two views? Do you have further evidence to support either the majority or minority view?

We support the minority view. Efficiency gains that rely on some cheaper SI generation are unlikely to eventuate from removal of HVDC charges from SIG. Refer to detail in question 5 above and Appendix A of this submission for supporting analysis that shows how credible alternative scenarios push the NPV negative, supporting the minority view.

Q9 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.

We do not agree with the summary of comparison, and in particular the NPV always appearing positive with transition and postage stamp options. Refer to explanation in Question 5 above.

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.

We have no comment to make on other possible variations of postage stamping HVDC costs.

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.

Notwithstanding our opposition to the TPAG majority view of a transition to postage stamping TPAG should consider aligning the transition to the merit order stack they have developed. It appears that the earliest SIG would be brought forward in the merit order is to approx five years. We think that the transition should not commence until this time and align as closely as possible with the "benefit" that would be realised from reduced whole sale energy costs.

HVAC

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

Yes we agree that co-ordination will be required to further develop analysis of deeper connection options and we encourage TPAG to continue with this work to as we agree with the TPAG assessment that there may be up to a $40M NPV efficiency gain available.

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.

We think it is reasonable likely that these gains can be realised, but is very dependent on the method of HVAC allocation that is applied. The greater the alignment of costs with beneficiaries the greater the likelihood efficiency gains will be made. We are generally in favour of a flow trace methodology with a deep asset concentration index.

Q14. 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?

Yes we agree with the range of options identified by TPAG for deeper or shallower allocation of costs.

Q15. 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.

We have no further information on these assessments to provide to TPAG.

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.

Yes we think there is justification to pursue options for a deeper allocation based on TPAG assessment of $15M to $40M NPV efficiency gains.

STATCOM

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?

Yes we agree with TPAG that there is a regulatory failure with power factor correction.

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

Yes we agree with TPAG selection of SRC options.

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?

Yes we are supportive of a minimum service power factor for USI and UNI. Further we support the TPAG proposal to adopt a backstop measure of 0.95 lagging and see the consistency of this limit across the whole grid as advantageous.

Q20. 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.

We have no further information or comment to make.

Q21. Do you agree with the TPAG's summary of the costs and benefits of the options assessed and its observations? If not, why not?

Yes we generally agree with the TPAG summary of costs and benefits.

Q22. 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?

We think minimum power factor should be retained in the LSI and LNI regions. Our view is that the Code rules are an incentive in themselves for participants to comply. We think that New Zealand does not always need a financial penalty to force compliance, and in this case, a reasonable power factor limit of 0.95 lag is very likely to be maintained.

Q23. 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.

We have no further comment on LSI and LNI power factor.

Q24. 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?

We have no further comment.

Q25. Do you support the recommended introduction of an amended kvar charge (option 4) into the TPM? Please provide reasons.

Yes we are supportive of the amended kVar charge being implemented in the USI and UNI regions. We agree with TPAG that there will be an efficiency gain of deferred transmission line upgrades through improved power factor. Further we think that option 4 encourages investment in SRC in the most cost effective way.

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?

We have no comment to make on the Draft Guidelines

APPENDIX A – LRMC Model

The model we developed is a spreadsheet based merit order built up from the Statement of Opportunities published in the MED Energy Outlook 2010.

http://www.med.govt.nz/templates/MultipageDocumentTOC____45553.aspx

Assumptions and notes.

- Load growth rate 1.5%
- Discount rate 7%
- All south island generators are grid connected and therefore subject to HVDC charges
- Reordering the stack – the most expensive LRMC generator sets price until next marginal generator built
- HVDC charge $28.2 / MW HAMI
- All 82 projects in the Energy Outlook are used. No projects are aggregated. (We understand TPAG took a conservative view of modelling the merit order to give a mean NPV $52.5M. We assume this to mean some projects where removed or aggregated)
- $40 Carbon price
- $13/Gj Gas price
- $4.5/Gj coal price
- 0.6 USD :NZD
- Does not allow for retiring of generation