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Submissions
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Transmission pricing methodology: problem definition working paper

We welcome the opportunity to submit on the Electricity Authority's Working Paper "Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets" (PDWP), 16 September 2014. No part of our submission is confidential.

We support the Authority producing a working paper on problem definition as part of the suite of transmission pricing methodology (TPM) review Working Papers. Getting the problem definition right is a vital step for any major policy review.

One of the ongoing areas of disagreement between the Authority and submitters on the TPM review has been over problem definition, and whether the Authority's proposals address, or are proportionate to, the problems with the TPM. It is clear the Authority perceives more problems with the TPM than most submitters.

Our submission is aimed at assisting the Authority to further advance the problem definition to help ensure it identifies areas where there are legitimate issues with the TPM, and to provide a robust foundation for the Options Working Paper and second Issues Paper. We make the following points:

1. **The PDWP is a positive step in the Authority's TPM review:** and represents a considerable advance on the previous attempts at problem definition, particularly in relation to the PDWP's assessment of the scale of problems with the RCPD and HDVC charges.
2. **In practice there is no perfect TPM:** we agree problems exist with the TPM and that these should be assessed (and addressed, as appropriate, where there are clearly superior alternatives to the current settings). We also agree there is no perfect TPM and consider that *perfect should not become the enemy of good*.
3. **We agree there are problems with price signals provided by HAMI and RCPD charges:** RCPD can over-signal the benefit of load-shedding and reduction in consumption while HAMI can discourage efficient peak South Island generation. These should be addressed promptly.
4. **We retain a number of concerns with the PDWP:** including the risk of hindsight bias, failing to account for changing market fundamentals and overstating the role of the TPM in grid investment decisions.
5. **Closing out the TPM review process:** is a priority for most if not all participants. The length of the review is creating considerable uncertainty. While the Authority should not rush the remainder of the process, particularly if substantive changes to the TPM are further considered, there are a number of lessons that can be taken from the review that would help ensure it is robustly completed in a timely manner.

We expand on each of these points below. A summary of our views on the Authority's assessment of problems with the current TPM is provided in the appendix.

1. PDWP IS A POSITIVE STEP IN THE AUTHORITY'S TPM REVIEW

We are pleased the Authority acknowledges the importance of getting the problem definition right, and that there were issues with the previous attempts at problem definition.¹

While we agree with the PDWP that the problem definition in the first Issues Paper could have been set out more clearly we consider the issues with problem definition extend beyond articulation. In this context the PDWP represents a substantial improvement on previous attempts to define the problem with the status quo; particularly in relation to RCPD and HVDC charges. While the PDWP has some deficiencies, it is helpful for providing a sense of the scale of potential issues with the status quo and better understanding the concerns the Authority has.

We agree the PDWP has correctly identified that there may be problems with the signals the RCPD Interconnection Charges send (over-signalling the benefit of load-shedding and reduction in consumption); and that the HVDC HAMI charges may discourage efficient peak South Island generation capacity.²

The sequencing is not ideal – but it is recoverable

The sequencing of Working Papers may not have been ideal, with Working Papers on TPM options (Connection Charges, Beneficiaries Pay, and LRMC) released in between the CBA Working Paper's attempt at problem definition and the subsequent PDWP. However, we do not see this as a fatal flaw in the Authority's process, or something that would inhibit the Authority developing a robust second Issues Paper. The key question is whether the suite of Working Papers support development of a robust problem definition, quantification of the scale of any problems, and identification of appropriate and proportionate TPM options for the second Issues Paper.

2. IN PRACTICE THERE IS NO PERFECT TPM

We are pleased to see further acknowledgement that "... there is no perfect TPM charge".³ This needs to be kept in mind when considering the PDWP assessment of the problems with the status quo.

The PDWP establishes that the current TPM is not perfect, and creates some static inefficiencies, which we doubt many parties would disagree with. The PDWP also establishes that there may be scope for improvements to be made to the TPM.

The status quo and the long-term benefit of consumers

It is premature and invalid for the PDWP to claim the status quo is inconsistent with the purpose statement in the Electricity Industry Act 2010.⁴

Until the status quo is assessed against other TPM options the Authority will not be in a position to determine whether or not it best meets the long-term interests of consumers. This will not be done

¹ These were provided by TPAG, the decision making and economic (DM&E) framework Consultation Paper, the first Issues Paper, and the Cost Benefit Analysis (CBA) Working Paper.

² Refer to Transpower, Transpower TPM Operational Review: Initial Consultation Paper, 9 July 2014, for our views on potential problems with Interconnection and HVDC charges.

³ PDWP, paragraph 8.8. The same point was made in the first Issues Paper.

⁴ PDWP, paragraph 1.18.

until either the planned Options Working Paper is issued, depending on its scope, or the second Issues Paper.

The Authority is on slightly safer grounds when it states that it “considers that the current TPM can be improved so as to better meet the Authority’s statutory objective”⁵ though until alternatives are evaluated the statement is somewhat speculative.

The risk such statements create is that they could be interpreted as pre-determining that change is necessary (i.e. the status quo is not an option) and pre-determining that a particular alternative TPM should be adopted. If the Authority forms the view that change is necessary before evaluating alternatives, and confirming they would better promote the long-term interests of end-users, it could also create the impression that the Authority applies low thresholds for regulatory intervention and undermine regulatory certainty and durability.

3. OUR ASSESSMENT OF THE PDWP’S REVISED PROBLEM DEFINITION

We agree the PDWP has correctly identified that there may be problems with the signals the RCPD Interconnection Charges send (over-signalling the benefit of load-shedding and reduction in consumption); and that the HVDC HAMI charges may discourage efficient peak South Island generation capacity.⁶ We also agree with Meridian Energy’s concern that where a charge is increased, e.g. the HVDC charge following Pole 3, any inefficiency impact will increase.⁷

To put the scale of the inefficiency (and the potential available efficiency) in context, two factors should be born in mind:

- because the inefficiency estimate is measured against an unobtainable ‘perfect’ counterfactual TPM the potential efficiency gains available are logically less than the estimated inefficiency⁸
- the inefficiency needs to be considered in context of the costs being recovered i.e. annual costs of ca. \$950m (incl. \$145m p.a. for the HVDC).

The inefficiency of the status quo, when assessed against an unobtainable ‘perfect’ TPM, is in a range from ca. 1% to 2.5% of the PV of transmission revenues (using the PDWP range of \$10M – \$243M PV⁹).

The efficiency gains available from an alternative TPM will be somewhat less than this. Therefore, while we support acting to address clearly identified inefficiencies (as we are doing through our own TPM operational review) we also urge caution and proportionality.

RCPD CHARGES AND NZAS’ SUMMER ELECTRICITY USAGE

The PDWP assesses both the static and dynamic efficiency impacts on the current RCPD charges reasonably well. The PDWP recognises that N=12 was set specifically to delay transmission investment upgrades (dynamic efficiency focus), while N=100 was set to reflect that there is sufficient transmission capacity for the foreseeable future (static efficiency focus).

The PDWP notes the following:¹⁰

⁵ PDWP, paragraph 2.2.

⁶ Refer to Transpower, Transpower TPM Operational Review: Initial Consultation Paper, 9 July 2014, for our views on potential problems with Interconnection and HVDC charges.

⁷ Meridian Energy, conference transcript.

⁸ In addition, change is not costless

⁹ Excludes purported durability cost of \$36.5M PV.

¹⁰ PDWP, paragraph 11.18.

The Authority's October 2012 issues paper set out that the RCPD charge may be justifiable if:

- (a) some transmission investment needs are driven by regional peak demand growth
- (b) participants respond to the RCPD incentive, resulting in regional peak demand that is lower than it would otherwise have been
- (c) the benefit of reducing the need for investment exceeds the cost of reducing demand.

We agree with these tests for whether it is desirable to continue applying dynamic pricing signals.

The PDWP goes on to note that "The Authority is not aware of any major transmission investments that could be deferred by reducing LNI [USI] [LSI] coincident peak".¹¹ The PDWP also notes that there are opportunities to reduce peak usage that do not incur efficiency costs. For example: "some industrials have informed the Authority that they are able to avoid peaks without any detrimental impact on efficiency. For example, Norske Skog has advised that "there is no loss of efficiency if load is shifted out of peak periods in order to avoid the charge" The Authority's \$5.5M PV may therefore be an overestimate provided the shifting of load does not result in foregone production".¹² Our assessment of the PDWP quantitative analysis of the RCPD charges is that it supports the position that the current N=12 should be removed, but we don't consider it provides a strong enough basis to conclude peak signalling should be removed altogether or that the lower level N=100 signal would be inefficient.

Submissions in response to our TPM Operational Review Initial Consultation Paper also support the position that peak pricing signals should not be removed completely. Representative excerpts from submissions include:

We believe 100 peaks is sufficient. We believe that 100 peaks has a reduced signal when compared to 12 peaks, however network companies will still use the load management systems that they have invested in to manage to the 100 peaks which is in the commercial interest of their customers.¹³

In our view, the UNI "N" should be amended to 100....

However, we do not agree that increasing the "N" to more than 100 is necessary or that to do so would be efficient. Analysis undertaken by Transpower in 2006 showed that demand peaks level off at about N=100, so, if a customer is choosing to control load at that level of "N" (probably irrationally, because the lost benefits from the load control are likely to exceed the transmission cost savings), further increasing the N would be unlikely to have any material effect on that behaviour. Also, as the "N" increases, the interconnection charge would increasingly resemble a per kWh charge, which could then have an inefficient effect on energy consumption and investment decisions by those customers that see the transmission charge separately.¹⁴

We suggest that N=100 is a sufficient number of peaks for regions in which RCPD charges are not intended to send peak pricing signals. Therefore, a review would not be required.¹⁵

...Vector would not support an increase in the number of RCPD periods beyond 100 in the UNI without further analysis, and compelling evidence that change is warranted, because: ... a) such a change would be material and is unprecedented; and ... b) as far as Vector is aware, there is no evidence that suggests more than 100 RCPD periods are required in the Upper North Island.¹⁶

¹¹ PDWP, Table 4.

¹² PDWP, paragraph 11.40.

¹³ Contact Energy, Re: Transpower TPM operational review: initial consultation paper, 8 August 2014, page 3.

¹⁴ Powerco, Re: Transpower TPM operational review: initial consultation paper, 8 August 2014, response to Question 6.

¹⁵ Trustpower, TRUSTPOWER SUBMISSION: TRANSPOWER TPM OPERATIONAL REVIEW, 5 August 2014, Appendix A: Response to consultation questions, paragraph 6.1.

¹⁶ Vector, Submission on Transpower TPM Operational Review: Initial Consultation Paper, 6 August 2014, Appendix A, response to Question 6.

We would not recommend stepping above $N = 100$.¹⁷

We, similarly, also broadly agree with the PDWP assessment of the impact of the current RCPD charges on NZAS' summer usage. We are aware of the size of NZAS relative to the LSI region, and that a relatively small change in its behaviour can determine when the 100 peaks occur and impact on the incidence of the charges on all users in the region.

Network Waitaki, for example, has noted:¹⁸

The load on Network Waitaki's network typically peaks in the summer months and is driven primarily by irrigation. The LSI region usually peaks in the winter, which is beneficial for Network Waitaki customers with regard to Transpower charges. However, because the load from the New Zealand Aluminium Smelters Limited smelter at Tiwai Point is so large and dominates the LSI region, production changes at that installation have in some years caused the LSI peak to coincide with Network Waitaki's peak, which has been disadvantageous in terms of higher Transpower charges and Network Waitaki's plans to mitigate them. We consider pricing signals in the LSI region as they currently stand to be unclear and too unpredictable ...

NZAS has provided evidence which demonstrates that its large size relative to the size of the LSI RCPD region is producing price signals that is deterring economic activity with no avoided transmission investment benefit.

NZAS has considered increasing production from late spring through to early autumn 2015 (and possibly in subsequent years). This increased summer production by NZAS would not affect transmission investment; however, NZAS has informed us that the increase in electricity consumption would shift some of the LSI regional peaks into the summer period (where NZAS' increased load would be coincident with it) making the production increase uneconomic.

The impact on the LSI RCPD is inefficient because the increases in intended electricity consumption is made uneconomic, not by increased transmission costs that would be incurred as a consequence of that consumption, but by the allocation of predominantly fixed and sunk costs.

NZIER, on behalf of NZAS, estimates the benefits from resolving these inefficiencies would be an additional 64MW of demand at NZAS for six months worth around \$14.8 million.¹⁹ NZIER also assess that "Should this demand remain for the entire term of the current NZAS electricity supply contract with Meridian (to 2030), the gross market value of the demand would be at least \$127 million (present value, discounted at 10% per annum)." NZIER conservatively assess that "The absence of this demand implies a loss of consumer benefits of at least \$3.2 million per annum. Over 16 years, to 2030, the cost is \$28 million."

IMPACT OF THE HAMI HVDC CHARGE

Despite stating that dynamic efficiency is more important than static efficiency,²⁰ the quantified evaluation of the inefficiency of the current HVDC charges in the PDWP appears to be predominantly based on static efficiency. That is, apart from consideration of Upper South Island transmission investment requirements, the analysis treats the transmission system as fixed. On this basis it identifies inefficiencies from discouraging peak generation in the South Island.

We broadly agree with the static efficiency assessment of the HAMI charges; and agree they discourage peak generation in the South Island (and, conversely, over encourage peak generation in

¹⁷ Mighty River Power, Transpower TPM Operational Review: Initial Consultation Paper, 6 August 2014, response to Question 6.

¹⁸ Network Waitaki, untitled submission via e-mail on Transpower's Initial Consultation Paper, August 2014.

¹⁹ NZIER report to New Zealand Aluminium Smelters Ltd, Accommodating load growth: Amending transmission prices to avoid inefficient demand loss, March 2014

²⁰ PDWP, paragraphs 5.3 and 5.4.

the North Island). This can result in productive inefficiency (more expensive North Island thermal being used rather than South Island hydro during peaks) and allocative inefficiency (higher prices as a consequence).

The static efficiency focus means, however, that while the PDWP considers "charges based on the long run marginal cost (LRMC) of transmission would provide efficient price signals about the cost of transmission investment", if the PDWP had evaluated LRMC pricing it would assess (quantitatively) that it is inefficient because it discourages South Island generation (productive inefficiency) and can result in higher (energy) prices during peaks (allocative inefficiency).

If the Authority is going to consider potentially dynamically efficient pricing options (such as LRMC) further, it is important the problem definition is well grounded in both a static and dynamic efficiency assessment of the status quo. This would require the problem definition to consider the impact of the HVDC on both transmission investment (including between North and South Islands, not just Upper South Island) and efficiency from the perspective of minimising aggregate transmission plus generation costs over-time when investment in both can vary. For example, the PDWP does not adequately consider the extent to which the current HVDC charges provide a (potentially dynamically efficient) North-South locational signal, which could delay the need for further investment in HVDC. If dynamic efficiency is more important than static efficiency the delay in transmission investment requirement may outweigh the cost of operating more expensive North Island generation.

The PDWP does not consider future HVDC upgrades and instead only focuses only potential upper-South Island transmission investment requirements (\$2M - \$6M PV cost).²¹

In summary, the PDWP:

- is predominantly focused on quantifying static efficiency impacts of the HVDC charges
- provides only a partial assessment of dynamic efficiency impacts e.g. it ignores the potentially dynamically efficient locational North-South Island signal, but considers potential distortion to Upper South Island transmission investment requirements.

What it might be useful for the Authority to assess as part of its ongoing TPM workstream, particularly if it intends to pursue potentially dynamically efficient pricing options such as LRMC, is:

- the extent to which HVDC investment is driven by peak network usage (or not)
- potential scenarios for timing of next HVDC transmission upgrade
- how close or far the current HAMI charges are from LRMC prices, including the extent to which they under or over-signal
- the extent to which current nodal pricing sends a locational signal (North Island versus South Island), and how this would compare to estimates locational or LRMC pricing.

4. CONCERNS AND CAUTIONS WITH CERTAIN ASPECTS OF THE PDWP

There is still work to do in order to land the problem definition, and we acknowledge the Authority's intention to further refine and develop its problem definition for the second Issues Paper.

²¹ The PDWP does not make this clear, but a potential problem with a simple North-South Island locational signal is that HVDC charges do not distinguish between generation investment in different parts of the South Island or North Island. While it may generally be preferable to expand generation in the North Island rather than the South Island (all things being equal), investment in the Upper South Island has the potential to defer a significant AC network upgrade and should, arguably, not be deterred.

We are concerned that, while the PDWP usefully identifies issues with the current RCPD and HVDC charges, it also risks overstating the size of the problems with the TPM, and potential gains available from changes to the TPM:

- A key part of the PDWP’s assessment of the TPM hinges on the claim that it is not “cost reflective” - this claim is overstated.
- The PDWP claims that the current TPM is not durable are without solid foundation.
- A change in the TPM is unlikely to result in the Commerce Commission making more efficient transmission investment approval decisions.

Each of these points is discussed below.

THE PDWP OVERSTATES THE EXTENT TO WHICH INTERCONNECTION AND HVDC PRICING AREN’T COST REFLECTIVE

A key proposition of the PDWP is the impact that non “cost reflective” prices have on efficiency:²²

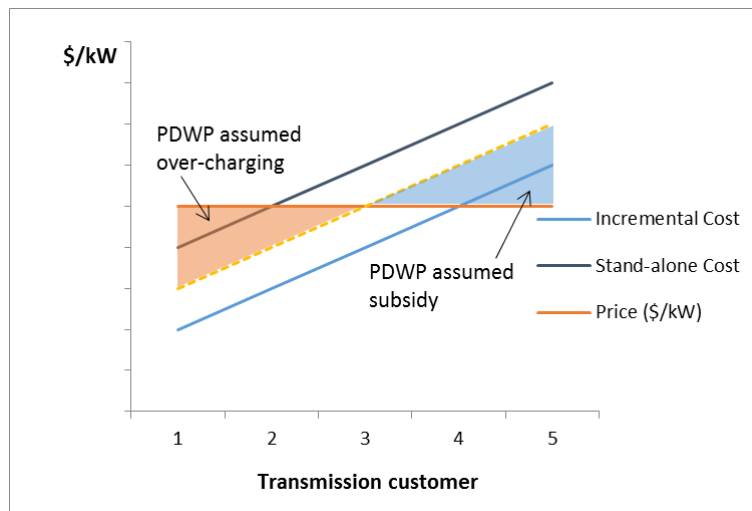
... The Authority considers there are three principal problems with the current TPM, namely:

(a) the HVDC and interconnection charges fail to promote efficient investment in transmission, generation, distribution, and by load (b) the current TPM is not durable (c) the HVDC and interconnection charges and PDP fail to promote efficient operation of the electricity industry.

Fundamentally these problems arise because parties pay interconnection and HVDC charges that do not adequately reflect the cost of supplying transmission services to them. (emphasis added)

The PDWP states that the “crux of the problem” is highlighted by its figure (we have reproduced and modified the figure (below) to better demonstrate the ‘crux’²³).

Figure 1: Problem of non-cost-reflective pricing under uniform price.



In our view the PDWP overstates the extent to which the postage stamp applied under the status quo results in charges that do not reflect the cost of supply.

A problem with the PDWP’s stylised figure is that it effectively assumes there is a single unique cost-reflective price for each customer that can be arrived at under an administrative process. If this was

²² PDWP, paragraphs 13.1 and 13.2.

²³ Refer to figure 1 in the PDWP.

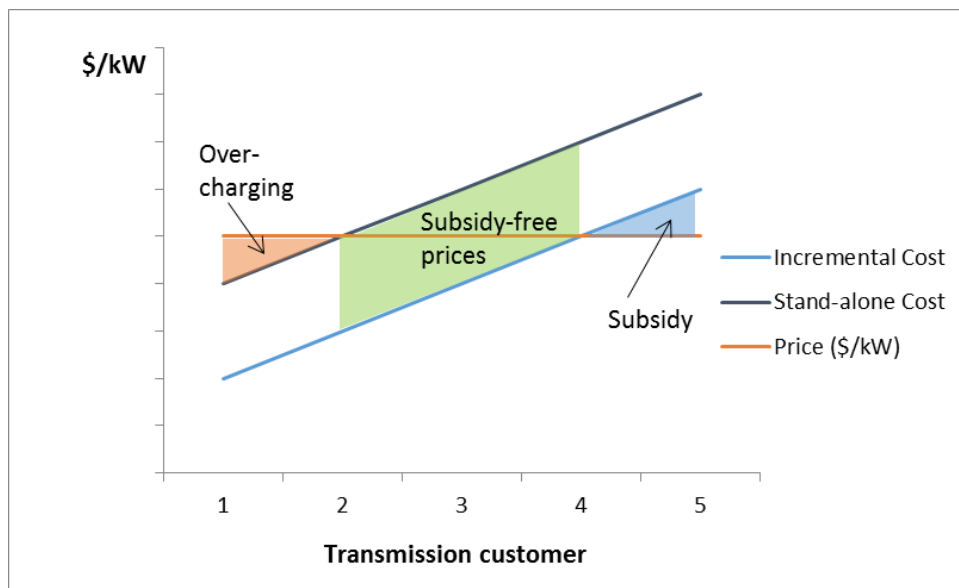
correct then transmission pricing would be a straightforward matter. The reality is that there is a wide range of “cost-reflective” prices.

When consideration is given to whether prices are “cost reflective” there needs to be clarity over what cost is meant to be reflected e.g. incremental cost (IC), stand-alone cost (SAC), fully allocated cost, marginal cost (short-run or long-run), average cost, variable cost etc.

The consultation paper on the DM&E Framework for transmission appeared to recognise these complexities, observing that determining cost-reflective prices would require an understanding of incremental cost “the impact that each interconnection user has on interconnection capacity, which will include the cost of augmenting multiple segments of the interconnection system”²⁴) and the complexity caused by joint and common costs (“the interconnected nature of the assets mean that it is not straightforward to uniquely associate peak injections or peak demand with interconnection capacity. Sometimes peak injection will constrain interconnection capacity and at other times it will not, and altering one component of the system can alter the power flows on all other components”²⁵).

The PDWP’s figure is most helpfully adjusted by recognising the large proportion of common costs means there is substantial divergence between IC and SAC and, therefore, a wide range of subsidy-free pricing (reflected in figure 2 below). This is a crucial point because many of the PDWP’s concerns are based on the proposition that the current TPM is not cost reflective.

Figure 2: Wide range of prices that reflect cost of supply of transmission services



What should be clear from figures 1 and 2, above, is that the PDWP has over-simplified the situation and, in the process, substantially over-stated the extent to which the current HVDC and interconnection charges diverge from “cost reflective” prices. This is highlighted by two PDWP concerns:

1. **Generators not paying any interconnection costs:** one of the main implications of generators not contributing to interconnection costs is that the charges to generators will be closer to

²⁴ Electricity Authority, Decision-making and economic framework for transmission pricing methodology review, consultation paper, 26 January 2012, paragraph 2.3.5.

²⁵ Electricity Authority, Decision-making and economic framework for transmission pricing methodology review, consultation paper, 26 January 2012, paragraph 2.3.7.

incremental cost than for direct connect customers and EDBs (who bear all joint and common costs). Whether there is a cross-subsidy from consumers to generators depends on whether connection charges are deep enough to cover the incremental cost of transmission services to generators (which is outside the scope of the current consultation).

2. **North Island consumers not paying for HVDC costs:** HVDC is needed to supply electricity from the South Island to the North Island. The fact that SI generators pay the entire cost and NI load receives some benefit from the HVDC does not necessarily mean there is a subsidy. It just means that SI generators pay closer to SAC (the upper limit of subsidy-free/cost reflective pricing).²⁶

In order to advance further the PDWP's consideration of cost-reflective pricing, any allocative inefficiency of the status quo needs to be evaluated by considering the extent to which Interconnection and HVDC charges vary from the IC/SRMC of supplying each of Transpower's customers. As acknowledged in the consultation paper on the DM&E Framework for transmission, this would require some form of "but for" analysis, or similar.²⁷

Specifically, the following analysis and questions should be addressed:

- *To what extent, if at all, does postage stamp pricing of interconnection [charging South Island generators for the HVDC] result in cross-subsidies between customers i.e. charges above stand-alone cost or below incremental cost?*
- *To what extent does the variation in implicit margin above incremental cost/SRMC as a result of postage stamp/averaged interconnection pricing result in allocative inefficiency?*
- *Is it more efficient/consistent with Ramsey Pricing Principles to recover joint and common interconnection costs from direct connection customers and EDBs rather than generators?*

Effectively the status quo means common costs are charged to EDBs and direct connect customers, and the charges to generators are closer to incremental cost. It should be noted that EDBs can pass on interconnection charges as fixed charges, but generators can only pass transmission charges on as variable (per MWh) charges.

None of the above is intended to suggest efficiency could not be improved by setting charges that are 'more cost reflective' or less averaged. Rather it is intended to make clear that the extent of any inefficiency with the status quo is less than the PDWP would suggest.

THE PDWP DURABILITY CLAIMS ARE NOT ROBUST

We do not believe the PDWP's discussion on "TPM charge durability" would cause many (if any) submitters to change their views on this matter, or that most interested parties would agree the Authority simply had not articulated its view on problem definition well enough. We thought the Authority's views on durability have been very clear.

The PDWP does not engage with or respond to previous submissions' criticisms of the Authority's views on durability.

The current TPM has been in existence for eight years without change. The major change that was made in 2008 to the TPM we had adopted in the late 1990s was to allocate interconnection charges among offtake customers using their share of regional coincident peak demand (RCPD) rather than each offtake customer's share of anytime maximum demand (AMD).

²⁶ This is also not uncommon where two-sided markets exist.

²⁷ Electricity Authority, Decision-making and economic framework for transmission pricing methodology review, consultation paper, 26 January 2012, paragraph 2.3.13.

Transpower's TPM Operational Review reinforces that the current TPM is durable, not the reverse. We would expect to periodically review the TPM regardless of what the TPM was – and it is likely that the more complex the price methodology the more frequently it would need to be reviewed.

We agree with Trustpower's view that "As it has been eight years since the current methodology was introduced, and significant transmission investment made in the interim, it is reasonable for Transpower to consider fine-tuning the existing TPM"²⁸ and "Operational reviews of this nature will enhance the durability of the TPM Guidelines".²⁹

Similarly, Transpower's NAaN exemption application simply reflected that an administrative pricing methodology cannot account for all future scenarios. The NAaN exemption application was made because we considered that the definition of interconnection did not properly anticipate multi-stage commissioning. This could be readily rectified with very minor changes to the TPM.

The fact that the Authority rejected the application would suggest the Authority considered there was nothing wrong with the TPM's definition of interconnection and the boundary between connection and interconnection.

Noting the efficiency and investment consequences the Authority attributes to durability we observe that:

- The regulator's own actions materially impact durability: if it is receptive to special pleading or lobbying then firms will respond accordingly.
- The Authority does not need to achieve consensus, on its TPM proposals, but there needs to be broad acceptance for any TPM to be durable and to avoid widespread pressure for further change.

And, related to that:

- There should be a high burden of proof that an alternative TPM would be to the long-term benefit of consumers before substantial changes are made.

THE PDWP'S VIEWS ON EFFICIENT TRANSMISSION INVESTMENT ARE UNSAFE

The PDWP does not engage with or respond to previous submissions which disputed the Authority's view that a change in the TPM would result in more efficient transmission investment approval decisions. We doubt that, as with durability, the PDWP's discussion on "The role of the TPM in supporting the discovery of efficient transmission investment" would cause many submitters to change their views on this matter.

We remain concerned about the Authority's views on the supposed link between the TPM, incentives, and efficient transmission investment approval. We do not agree with the PDWP theme (expressed in Table 9) that "The TPM fails to promote efficient investment in transmission, generation, distribution and by load". This is largely a reiteration of the views that all but one submitter rejected in relation to the first Issues Paper.

The PDWP analysis focuses on two main points:

- the incentives on parties to participate in the choice of preferred option
- the timing of the preferred option

We comment on each below.

²⁸ Trustpower, TRUSTPOWER SUBMISSION: TRANSPOWER TPM OPERATIONAL REVIEW, 5 August 2014, paragraph 3.1.2.

²⁹ Trustpower, TRUSTPOWER SUBMISSION: TRANSPOWER TPM OPERATIONAL REVIEW, 5 August 2014, paragraph 1.1.2a.

Incentives on parties to participate in the choice of preferred option

The processes run by the Commerce Commission (and the Electricity Commission previously) for major transmission investment requires significant consultation by Transpower as the investigation progresses. All interested parties may participate and respond to consultation papers and questions. Probably the most important part of our consultations (in terms of ensuring efficient investment) is the list of options to be considered and this is the aspect we get most engagement on. In our experience the process works well. If the process worked as the Authority describes, we would be receiving option suggestions that maximise service to those who receive more service than they pay for and minimum service suggestions from those who receive less than they pay for. We have not observed such behaviour.

Timing of the preferred option

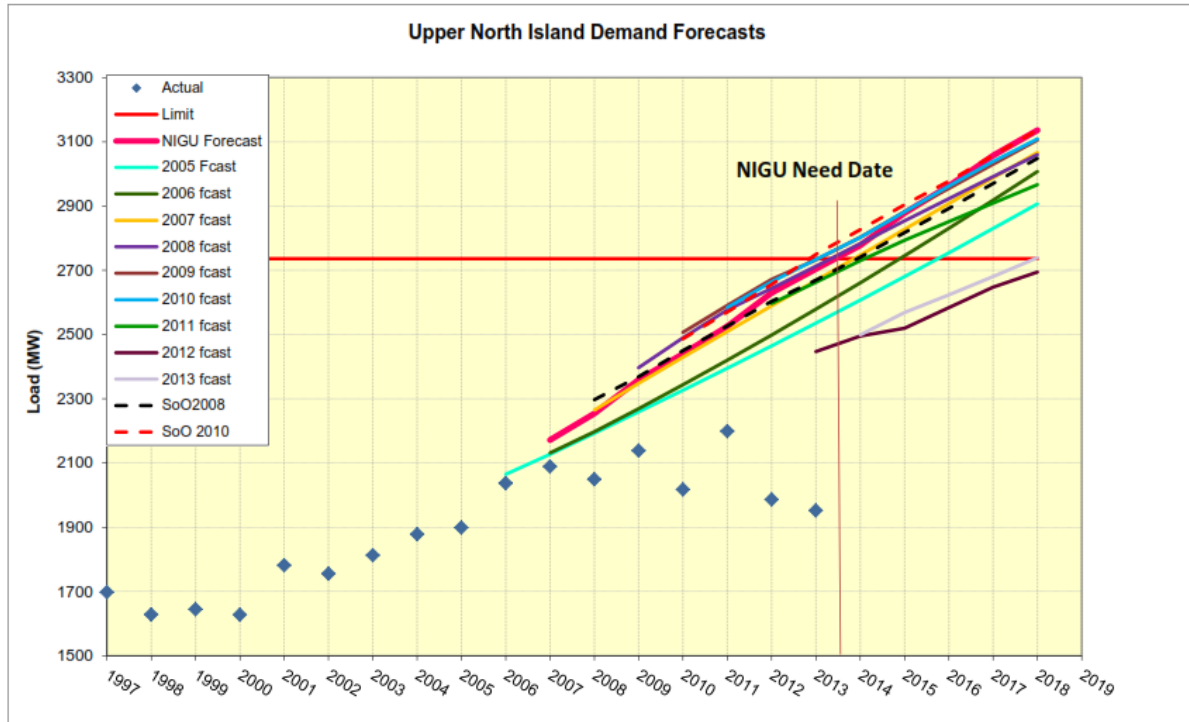
The approach we use to determine the optimal timing for investment reflects a particular view of electricity consumers' preference for risk. In words, that view has been broadly described as "the costs of building too late are far greater than the costs of building early". We undertake our analysis of optimal timing by using prudent demand forecasts which consider a P90 view of short term demand. This is to ensure there is only a 10% chance of building too late. By definition though, that also means that if we commission a project on time and demand growth is at an expected, or P50 level, we actually commission the project earlier than required. That said, even if a revised TPM did encourage more interaction in investment decision-making, it would have little influence over the analysis of optimal timing. A change to that approach would need to be determined separately.

Whether a project can be deferred after it is approved and underway depends on the nature of the project. Some projects can be built in stages (e.g. Lower South Island Renewables), with logical hold and review points, but for many that is not possible. For a major construction project, it may be feasible to pause it prior to construction commencing but after that, such costs become prohibitively high and it is nearly always more economical to complete the project. For projects with a long build time, that can mean, even though circumstances change during the project build, it is uneconomic to stop the project. The North Island Grid Upgrade Project (NIGU) is an example of where that occurred.

NIGU example

The Grid Upgrade Plan for the NIGU Project was submitted in 2006 and approved by the Electricity Commission in 2007, using Electricity Commission 2006 demand forecasts. The figure on page 12 shows prudent demand forecasts from 2005 through to 2013.

Figure 3 – Upper North Island prudent demand forecast, 2005 – 2013



As figure 3 illustrates, although demand has remained flat since 2007, that trend was not obvious after 2011 and revised prudent forecasts broadly coincided with a 2013 need date through until our 2012 demand forecast was issued.

When key decisions for the delivery of the NIGU Project were being made in 2009 and 2011, we were still of the view that 2013 was the need date for the NIGU Project, based on assessment of the information available at the time.

Consequences of lower demand growth forecasts

In light of lower demand forecasts we have extensively reviewed planned and approved large capex projects to assess deferral options. One outcome of this review was our decision to suspend our Lower South Island Renewables Project. Although the project was approved by the Electricity Commission we determined, having regard to changes in supply and demand, that it was appropriate (including from an economic management perspective) to defer the majority of this project.

Such an option was not reasonably (or economically) available for NIGU, which at that time was only months away from commissioning. A deferral of the commissioning date at that stage of the NIGU Project would have been a significantly more expensive option than proceeding to completion within the timetable envisaged.

Link between TPM and engagement in transmission investment is tenuous

We do not consider that Appendix C provides any useful information on problem definition. Appendix C has a number of problems, including that it suffers from the same ‘the problem is we don’t have beneficiary’s pays’ issue as the problem definition analysis in the first Issues Paper. Overall it overstates: (a) the link between the TPM and the engagement of interested parties in the investment approval process; and (b) the effect that an increase in price-motivated engagement

could have in a net benefits investment test. We do not believe it supports the contention that the TPM results in inefficient transmission investment approval decisions.

Appendix C also contains inaccuracies. For example, Appendix C incorrectly lists Meridian Energy and Trustpower as opposing Pole 3. Both parties provided strong support for the investment, as illustrated by the following extracts from the Electricity Commission's HVDC Grid Upgrade Proposal Conference, 22 September 2008:

Tim Lusk (CEO of Meridian): "... in Meridian's view, the national benefit is undeniable. If there is any hesitation arising from the most detailed analysis, experience and judgment must prevail. The real case is overwhelming and speed is of the essence ... Meridian strongly supports the Electricity Commission's draft decision to approve the investment and replacement of pole 1. It is in the national interests.

Peter Calderwood (Trustpower): "... the HDVC does pass the GIT and, we, like all the other submitters agree it has met net public benefit. From a national good and net public benefit test, it should go ahead. We have no dispute of that at all."

The notion in the PDWP and the first Issues Paper that beneficiaries-pay would result in better information for transmission investment approvals is countered by the listing of a substantial number of parties that have not submitted on investment approvals where the cost to them is outweighed by the benefits (or submitted in favour). The fact that Vector "who is the main beneficiary of NAaN, and yet faces only a portion of the costs, advocated strongly for the investment to go ahead"³⁰ does not indicate a problem. Rather it reflects the near industry consensus that the investment should go ahead.

Moreover, submissions to the Electricity Commission on transmission investment should be considered in the context of a period of under-investment in electricity transmission. Most submitters were concerned about remedying under-investment, rather than the risk of over-investment in electricity transmission. There was also a general concern that the approach the Electricity Commission was taking to transmission investment approval would understate the benefits (the NAaN being a case in point). In that context, the submissions from EDBs and gentailers are unsurprising.

Risk of hindsight bias

A further caution is that any ex-post analysis of this type is susceptible to hindsight bias.³¹ The risk of hindsight bias is elevated when there have been fundamental changes in the market conditions over the period in question, as there have here. We would, consequently, caution the Authority against reading too much into the positions of various stakeholders in the lead up to investment decisions (or the actions of Transpower, our regulators and stakeholders as the investments were implemented).

These factors, coupled with the outlook for grid investment (a function of the level of existing constraints and demand growth) seem highly relevant to any analysis of the emphasis given to static vs dynamic efficiency objectives in the TPM. That an assessment of the factual situation will help provide a real world overlay to a theoretical exercise is hardly controversial – but seems especially pertinent given the timing and duration of this review.

Situational assessment: future transmission investment and scrutiny

In analysing the role of the TPM in motivating interested parties to engage in investment approval processes the Authority should bear in mind, as well as the factors outlined above, the following points:

³⁰ PDWP, paragraph 9.12.

³¹ Hindsight bias is a term used in psychology to explain the tendency of people to overestimate their ability to have predicted an outcome that could not possibly have been predicted.

1. Since the Authority initiated its review, the incentive framework applicable to Transpower (and EDBs) has evolved and matured. As we set out in our response to the Connection Charges Working Paper Transpower faces strong incentives to optimise expenditure to achieve the lowest whole of life costs for the service we deliver. We retain one third of every dollar of approved base capex expenditure that we can avoid (and benefit from the time value of money for deferred expenditure). As an organisation that translates into a strong incentive to scrutinise, test and challenge every assumption made by our customers (distributors, generators, direct connects) or any other party involved in the investment planning process
2. Increasing competition and political attention are constraining retail price increases. This pressure on cost flows through into increased scrutiny by retailers of lines company costs at all levels – whether investment, operating or cost of capital.
3. In a recent presentation to the Business NZ Energy Council the Commerce Commission outlined the following ‘emerging challenges’ faced by electricity lines companies including Transpower:
 - future demand
 - disruptive technology
 - affordability and fuel poverty
 - death spiral
 - changing consumer expectations
 - new business models
 - climate change (extreme weather)

The emerging challenges identified by the Commerce Commission combine to create greater uncertainty and risk for investors that result in a more cautious approach to investment. That is particularly relevant to the type of large, capacity expansion investment that might be influenced by transmission pricing signals.

When coupled with points 1 and 2 it is difficult to see what if any further transmission investment efficiency benefits could flow from increasing TPM motivated engagement in the investment approval process.

5. CLOSING OUT THE TPM REVIEW PROCESS

The PDWP is a welcome and positive step forward but it continues to overstate the problems with the status quo. That risks directing the Authority down a path of radical change which most submitters continue to view as disproportionate to the actual problems with the TPM. If this happens, the Authority could find itself in a situation where the feedback it gets on its planned 2015 Issues Paper mirrors the responses to the 2012 Issues Paper.

The Electricity Authority’s TPM review has taken much longer than was originally anticipated. We had originally anticipated that we would be able to implement the Authority’s first Issues Paper proposals by April 2015. As matters stand, the Authority won’t have consulted on its preferred options until after then. This contrasts with the way the Authority expedited the Government’s section 42 Electricity Industry Act priorities; particularly in relation to hedge market development which had drifted for a number of years under the Electricity Commission.

Paradoxically, the Authority’s extended review period is creating significant regulatory uncertainty, and risks undermining the durability of the current TPM (and any potential revision or replacement of the TPM). Large scale TPM reviews impose significant costs on the industry both directly (in terms of their engagement and funding of the Authority via its levy) and indirectly in terms of the

opportunity costs of devoting specialist resource and management time. While the process so far has been aptly described as “sunk” we are conscious there is a considerable amount of further policy development required before the Authority’s TPM review will be completed.

As we have done all along the Authority’s TPM review process, we will continue to provide information that should assist the review. The most recent being papers assessing the impact of the current N = 12 and 100 settings, and the impact of using HAMI v MWh for allocating HVDC charges to South Island generators. We would be more than happy to engage with the Authority on further analysis that could assist the review. For example, if the Authority considers LRMC or locational pricing options further it may be useful for us to revisit our assessment of the impact of a tilted postage stamp.

We would advise the Authority to:

- Carefully assess the views expressed on the extent to which there is a problem with the TPM; particularly in relation to durability and transmission investment approval decisions, both in response to the PDWP and previous consultations.
- Take account of how the electricity market is evolving – including flattening demand, significant uncertainty, a relatively unconstrained grid and very limited load-driven enhancement and development investment in the foreseeable future. This may have implications for the relative benefits from promoting static efficiency versus dynamic efficiency.
- Assess the extent to which the current TPM does, or does not, already reflect cost-reflective pricing by evaluating the extent to which the Interconnection and HVDC charges vary from the IC/SRMC and SAC of supplying each of Transpower’s customers.
- Make sure that if dynamically efficient pricing options such as LRMC are considered that the status quo is fully assessed on both a static and dynamic efficiency basis.
- Give greater prominence to Principle 4 in the Consultation Charter that there should be a preference for “options that are initially small-scale, and flexible, scalable and relatively easily reversible with relatively low value transfers associated with doing so”.³²
- Recognise that for any TPM to be durable there needs to be a general level of comfort and buy in (not necessarily consensus) from affected parties. It does not matter how theoretically perfect an option is if it has little or no support.
- Make sure the options Working Paper is open to and canvasses a broad range of options that have been identified in consultation and submissions so far, including enhancements to the status quo, changing the allocation of the HVDC (which has been the key impetus for TPM review), intermediate options such as tilted postage stamp, and more radical options such as beneficiaries-pay and full LRMC pricing.

CONCLUSIONS

The specification and measurement of problems with the TPM is an important first component of the review of the TPM.

We would caution though that the identification of inefficiencies with the status quo does not mean the TPM should be amended or replaced. Any change to the TPM brings about its own inefficiencies (no TPM is perfect), transaction costs and risk.

³² Electricity Authority, Consultation Charter, 19 December 2012, Principles 4, page 5.

As indicated previously and again in the submission, we would be more than happy to further assist the Authority with its problem definition work or the TPM review where this would be helpful.

Please do not hesitate to contact me if you would like to discuss any of the matters covered in this submission or our views on the TPM review more generally.

Yours sincerely,

Jeremy Cain
Regulatory Affairs Manager

Appendix: Our assessment of the key concerns expressed in the PDWP

| PDWP concerns | Transpower assessment | Recommendation |
|--|--|--|
| "... there is no perfect TPM charge" | Agree. | Acknowledge that any alternative TPM will not be able to remove all inefficiencies and will create inefficiencies of its own, and that change can be costly. |
| "... the current TPM fails to promote the Authority's statutory objective of promoting efficient operation of, competition in, and reliable supply by the electricity industry for the long-term benefit of consumers" | Disagree. Adverse efficiency impact of status quo is relatively minor (see below). There may be scope for an alternative or variation on the status quo to <u>better</u> promote the purpose. | Make preliminary assessment on whether an alternative TPM would be materially better than the status quo at the second Issues Paper stage, not now. |
| "... the current TPM can be improved so as to better meet the Authority's statutory objective" | Unproven. This can only be assessed by evaluating alternatives to the status quo. | Avoid predetermining that the TPM should be changed. This is properly assessed as part of the consultation on the second Issues Paper. |
| Quantified TPM inefficiency | Up to 2% of transmission revenue (on PDWP analysis). | Inefficiency is relatively small but worth investigating. |
| Quantified HVDC inefficiency | Up to 3% of the PV of HVDC revenue (on PDWP analysis). | Inefficiency is relatively small but worth investigating. |
| RCPD Interconnection Charges can over-signal the benefit of load-shedding and reduction in consumption; and the HVDC HAMI charges can discourage efficient peak South Island generation capacity. | Agree. | Amendment of Interconnection and HVDC charges warrant consideration commensurate to their inefficiency. |
| TPM prices are not "cost reflective" | Overstated. | The Authority would have to undertake "but for" analysis to establish the extent to which current TPM prices are "cost-reflective" or not. |
| Durability concerns with the current TPM | Overstated (durability is a reason not to change the TPM), potentially invalid. | Consider durability as a disadvantage of significant changes to the TPM. Suggest removal from problem definition. |
| TPM-incentives-transmission investment approval link | Invalid. | Suggest removal from problem definition. |