Transmission pricing

Assessment of Transpower's proposed variation

NZIER report to MEUG

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Final

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1. Introduction

1. The Electricity Authority (Authority) have released a consultation paper that is prompted by a number of variations that Transpower propose to make to the current Transmission Pricing Methodology (TPM).

2. Transpower published and consulted on their variations during 2014 and submitted their formal change request to the Authority in December 2014. The Authority rejected part of Transpower proposed changes and made its own modifications to most of the remaining parts which is what has been published for consultation. The EA modifications mainly relate to the choice of options that could be considered when evaluating the Transpower RCPD variation and to the nature of the CBA.

3. This report to MEUG provides NZIER advice and assessment of the Authority paper on those variations to the current TPM. The Authority is seeking feedback from stakeholders via 21 specific questions from their consultation paper. We have set out our initial thoughts on responses to these questions and in the sections below we also provide our comments on the approach of the Authority to the Transpower variations.

4. NZIER were asked to test the assumptions and arguments in the Authority analysis with real world data and to provide our analysis and assessment of the variation proposal regarding replacing the RCPD N = 12 with an alternative. We were not required to examine the options regarding changes to the capacity measurement period in any detail.

1.1. Is there a real problem

5. As part of various consultations on changes to the TPM over recent years, the Authority has consulted on what it perceives as problems with various aspects of transmission pricing arrangements. The problems that the Authority believes are driven by the TPM and the appropriate solutions have however evolved over time. Recently there have been three attempts to identify and quantify the problems with the current TPM. In late 2014 the Authority received extensive feedback from stakeholders regarding the materiality of the potential inefficiencies identified by the Authority.

6. NZIER have been consistently of the view that the problems the Authority (and now Transpower) perceives as being real issues, that are attributable to the TPM, have not been adequately defined or evidenced. While these three attempts have redefined the drivers of the ‘problems’, to us they do not appear to have led to either a stronger quantitative evidence base or a convergence of the estimates of the costs and benefits of the current TPM regime.

7. As before, we also remain of the view that the Authority problem definitions has a tendency to:

   - oversimplify the decision making processes for MEUG members on both production and co-generation, as well as over-emphasising the influence of transmission prices on these decisions

- overstate the capability of consumers to understand and influence transmission investment decisions

The September 2014 problem definition

8. Transpower seems to also believe that changing the TPM can improve both the efficiency of the operation of transmission, generation, distribution networks, and demand side management, as well as the efficiency of investment across the sector. The Transpower variation paper is very much an extension of the September 2014 problem definition paper.

9. In their September 2014 problem definition paper the Authority 'addresses' previous criticisms about the complexity of their arguments, and supporting models, by using spreadsheet models rather than the investment (GEM) models, but they stick with their assertions regarding the existence of inefficiencies from the current TPM. Despite these improvements, the Authority does not however demonstrate how the spreadsheet models remove complexity in the pricing 'system' while still providing reliable predictions about how the system behaves. These weaknesses show through again in the analysis behind the current variation.

10. A key observation that we made at that time was that the Authority:

> "*… has expressed considerable concern about the effects of embedded and co –generation installations. We read some of the Authority concerns with alternative generation sources within the distribution network, or inside of direct-connect customer's premises, as having the potential to discourage innovation and dynamic growth in the sector when one should see competition as a priority when thinking about efficient outcomes*".[1]

11. We are of the view that there are other aspects of the consultations by the Authority on the TPM that also need consideration:

    - How the proposed Transpower problems & solutions fit with upcoming review of the TPM by the Authority. The Authority notes it is working on various options that in its view there are better solutions than the Transpower variations[2]. They do not say what problem they will be addressing with their options however.
    - There is a growing acceptance of the importance of the dual pressures of declining demand and developments and disruptions on the supply side that need to be considered when making any changes within the regulatory framework. We have commented on these developments in earlier advice to MEUG that we will not repeat here.[3]
    - The EA and Transpower seem to have a high level and broad/sweeping view of 'demand side responses' to transmission pricing in general and the negative impact that these assumed responses have on grid efficiency. They do not consider the more detailed logic and economics of demand side

1 See 'Transmission pricing problems – Assessment of the 2014 EA problem definition'. NZIER report to MEUG 28 October 2014.

2 See "Transpower's proposed variation to the Transmission Pricing Methodology, Executive Summary" p8.

3 See 'Memo to MEUG on Input Methodologies review – Commission scope letter' 20 March 2015.

activities that have an impact on grid and system use – such as using production waste heat to fuel own (co-) generation; or use local resource (geothermal) to generate local electricity because it provides a more predictable pricing signal or solar which offers consumers a local renewable electricity source.

- Rocking back from the detail of these arguments, it is easy to imagine that the regulatory system objective (efficient use of the grid) is becoming a more complex problem to solve due to the way the electricity markets are evolving including:
  - Flattening demand and uncertainty about the outlook the level of industrial demand.
  - Potential change with residential users patterns for use of the grid.

12. Technology and network economic trends are seeing costs of the networks becoming higher than generation and are forecast to continue to increase. As such network costs are now becoming the binding constraint on power costs and quality. Therefore we believe that future efficiency improvements will likely come from locating smaller generation units closer to demand and make use of economies of scale in smaller units (that is, volume based economies may be higher than the previous economies that came from large unit size of big generation)
13. These factors all combine to make it harder to predict what grid investment will be required and increase the risk of stranded assets if investment is based on a continuation of past demand assumptions.

2. Components of the solution

14. Moving on from our comments regarding the Authority's perceived problem with the TPM, in this section we look at the solutions that the Authority has on the table for consultation. Our review and assessment in section 2.1.1 to 2.1.5 are our analysis and critique of what the Authority propose for changing the RCPD 'N' value.

15. Following two consultation processes during 2014 Transpower proposed a set of operational 'variations' to the current TPM in a letter to the Authority dated February 2015. Transpower's final proposals were to:

    a) increase the number of charging periods from 12 to 100 for the Upper North Island and Upper South Island regions

    b) put bespoke arrangements in place to improve pricing stability in the Lower South Island and to support increased summer production at the Tiwai aluminium smelter

    c) change the basis for allocating HVDC costs to South Island generators from peak (MW) to average (MWh) injection

    d) put a mechanism in place to deal appropriately with reverse flow situations; and

    e) modify the averaging approach for lines maintenance costs.

16. Transpower set aside their previous proposals to modify the pricing regions and to reduce HVDC charges to USI generators, pending the TPM review work that the Authority is undertaking in parallel to these operational changes.

17. The proposal that the Authority is consulting on is different to the Transpower February proposal and to the previous consultations. The Authority referred three of the February components (components b, c and e in para 13 above) back to Transpower. They also made a series of modifications to the main component to change N = 12 to N = 100 for UNI and USI. Following discussions between Transpower and the Authority in April 2015 two more components were added to the two remaining Transpower variations (these being the summer CMP and quantity adjustment provisions).

18. The final Authority proposal is therefore a combination of two components of the original variations that were consulted on by Transpower and several new variations that have not been consulted on prior to now.

19. Since the Authority consultation paper was published in April 2015 Transpower have resubmitted their original proposal, without modification, to change the HVDC charging arrangements. The ongoing difference between Transpower and the Authority on the modification to HVDC charging combined with the Authority's belief *"that there are superior alternatives that are not consistent with the current TPM Guidelines. Such alternatives could be considered as part of the Authority's review of the TPM",* create considerable uncertainty about the scope of consulation on this TPM variation and the durability any decisions made by the Authority.

2.1. RCPD N = 100 for all TPM zones

20. Currently not all transmission pricing zones have the same peak demand charging structure (UNI = 12, LNI = 100, USI = 12, LSI = 100). The Authority and Transpower are of the view this is now less than efficient and that there will be a lower level of 'inefficient demand response' if all zones have the same RCPD N number (or that a method other than RCPD is used to allocate Transpower revenue requirements to users of the transmission grid).

21. The focus of the evaluation of this variation by the Authority is the efficiency impacts of the RCPD charging mechanism. In the past the RCPD was used to temper the growth in demand in particular locations and at particular times such that investment in, and operation of, the transmission grid could be more efficiently conducted. Transpower argues that allocation of interconnection charges in in the Upper North Island (UNI) and Upper South Island (USI) based on N=12 now 'over-signals' the value of load shedding or embedded generation. However Transpower only provides rough indication of the estimated load shedding.[4]

22. In section 4.3.1 of their paper the Authority describes the proposed amendment to N = 100 as having two objectives:

    - To promote grid efficiency by reducing the incentives for inefficient demand response investments and operations; and
    - To continue to be able to defer grid investments by using RCPD as the revenue allocator.

23. The first objective has a sole focus on efficient use of the grid and is the narrow frame for the Authority evaluation of costs and benefits. Because of this the Authority CBA evaluation is very limited and leaves us questioning whether the CBA is a fit-for-purpose tool in this context. (We note that the Transpower and Authority estimates of both the capacity and cost of load shedding/embedded generation are markedly different. It is also not clear how the Authority has reconciled its estimates of the increased investment in the grid as a result of the changes proposed by the Authority with Transpower estimates for grid investment.)

24. The second objective has a focus on efficient investment in the grid to provide capacity to meet peak demand growth. Peak demand charging is a common mechanism to defer grid investment. Transpower believe that changing to N = 100 will continue to meet this objective.

25. The Authority proposal to change to an allocator based on a flat charge (such as gross MWh or LRMC) that does not recognise contribution to peak demand and therefore fails to meet this objective from the outset. The net present value of the efficiency gains for both the Transpower proposal and the Authority proposals is very small in comparison to the net present value of the interconnection charge that they affect. The low level of the potential benefit combined with the uncertainty around the assumptions used to calculate the benefit suggests to us that the case for change is indeterminate at best.

[4] See "8-Attachment-D-TPM-OpRev-Price-Effects-and-RCPD-avoided-costs-13Feb2015" worksheet "RCPD N Avoided costs"

2.1.1. What is being proposed

26. In the consultation paper the Authority includes both a regulatory assessment and a cost-benefit analysis of the Transpower proposal to continue to use RCPD as the allocator of Transpower revenue. They state that they do not wish to change other aspects of the current TPM code but despite saying this they do propose that specific additions be made to alter capacity measurement rules.

27. The Authority is of the view that the change to N = 100 for all regions will be a net benefit to consumers. We discuss their views and the CBA in 2.1.5 below.

2.1.2. Regulatory statement - RCPD

28. The Authority expresses very tentative views regarding the levels of confidence they have in the assumptions used to estimate the net benefits. From the Authority's formal consultation questions it is looking for input to improve its comfort levels about both its estimates of the capacity and cost of load shedding/embedded generation as well as whether the proposed variations will have the desired effects. The Authority seems confident that the greater number of peaks will mute the peak load signal and discourage what it regards as inefficient under-use of the grid. The Authority seems a lot less confident that their second objective (in para 22 above) will be met and whether the pricing signal will continue to yield transmission deferral benefits.

29. This is somewhat concerning in that the Authority views of whether the changes will yield benefits seem to be built from the inputs - assumptions that current demand behaviours are inefficient and therefore that the proposed changes will yield benefits. These two assumptions feed into the CBA and give rise to a series of assumptions that drive the costs and benefits from the change. In the same manner as for the problem definition, to us the Authority is missing a solid foundation of evidence on which to build an assessment of this particular variation.

30. Interestingly the regulatory statement does not use the Transpower CBA (or Transpower estimate of benefits) with the Authority preferring to make their own assumptions. The Transpower February 2015 letter to the Authority included a background analysis paper as an attachment in which a number of potential benefits from the proposed options is described but it stopped short of an evidence driven CBA. In the same manner as Transpower and the Authority previous estimates of costs and benefits from changes to the allocation of Transpower revenues we regard both of these as illustrative and comment further on technical specifics below.

2.1.3. EA options to RCPD = 100

31. Both Transpower and the Authority report on their considerations of alternatives to the change from N = 12 to N = 100. Transpower reported on their assessment of 5 options (including their preferred N = 100) in their February 2015 supporting analysis, in descending order:

Table 1 Transpower options

Option	Transpower preferences
N = 100 for both UNI and USI	First choice
N = 100 for UNI only	Second choice
N = greater than 100	Limited effectiveness - discard
Other tariff designs (MWh, MAD, winter only)	Discard – too novel
Status quo	Not considered as an option

Source: NZIER

32. Transpower felt that change was warranted now and setting time aside to carefully evaluate other options was not an efficient use of time and resources. Transpower was positive in its view that benefits would be realised from immediate change rather than delay and that novel options for allocation of revenue such as MWh and maximum anytime demand would generate too much response to be worth the effort at this stage. Their preference was to leave the evaluation of other options to the Authority's own TPM review. We think that this is a pragmatic and sensible approach.

33. The Authority has a different view to Transpower. In the consultation paper the Authority considers 7 options for addressing the objectives as follows, (though not in any order):

Table 2 Authority options

Option	Authority views
N = 100 for both UNI and USI	Transpower proposal
N greater than 100	Possible
Per MWh charge	Possible
Per winter MWh charge	Discarded
Tilted postage stamp	Discarded
Anytime max demand	Discarded
50:50 RCPD and per MWh	Possible - balances objectives
LRMC and per MWh	Possible - reflects peak investment cost

Source: NZIER

34. Section 4.5 of the Authority paper evaluates these 7 options from a number of qualitative angles, with an eye on whether each option can be seen to be in sync

with the Authority decision making and economic framework. They like the LRMC option for this reason. Section 4.5 also describes a preference for charging on a MWh basis but on gross load only rather than on gross less embedded generation (net), though the Authority do admit to probable measurement problems with this approach.

35. Section 4.5 concludes with a very tentative conclusion that N=100 is preferred over alternatives even though the Authority admits to some difficulty with determining whether the benefits are positive or negative. The other conclusion from the section 4.5 evaluation is a statement by the Authority that it believes that there are superior options that will however require a change to the TPM.

2.1.4. EA assessment of N=100

36. The cost benefit analysis (CBA) assessment of the proposed charging options is dependent on Authority assumptions on the embedded generation/load control capacity and cost. The scope of the CBA is limited to how the change in the connection cost allocation affects the value/cost of electricity traded around peak periods relative to the base case. The options are compared on their discounted net present value over a 15 year period. The Authority CBA considers 5 connection charge allocation options for each of the base case plus four alternative scenarios covering a mixture of assumptions about the requirement for transmission investment and elasticity of industrial load. The Authority does not express a view on the relative likelihood of the scenarios.

37. The Authority's working assumptions include a view that transmission investment will be needed in the foreseeable future at an LRMC of up to $80/kw and that interconnection charges will have no impact on either embedded base load or intermittent new generation. If this means that embedded and co – generation do not respond to the level of the interconnection charges, only to the LRMC, then we question the assumption because it is the overall cost of supplied electricity that is used in a co-gen business case rather than just the long run cost of energy.

38. The Authority, by admission, regard the CBA analysis as illustrative (we do as well), rather than asserting that any of their assumptions or options reflect a possible or probable future outcome. Despite this strong caveat the Authority rank each of the charging options from Table 2 above based on their net present value estimated from the Authority's CBA and conclude that:

- the status quo (N = 12) is not preferred under any of their assumptions
- the proposed variation is preferred if you accept their assumptions for the base case situation
- the other charging options in Table 2 may be preferable if alternative assumptions are considered (Cases A to D).

39. It seems to us that the Authority do not believe that their CBA provides them with enough precision to base a decision on – we agree with this conclusion but we go further in the next section of our assessment and suggest that the cost benefit analysis itself is not a good enough tool to use in making a decision on the proposed variation.

2.1.5. Cost benefit analysis

40. Our concerns with the CBA lie in the detail of the assumptions used in the CBA. The detailed analysis of some of the costs and benefits seems to us to fall short of the requirement for the cost benefit analysis of a code change, particularly for the structural change considered under the gross MWh charge option and its related hybrids.

41. We have four broad areas of concern with the CBA:

- an apparent lack of evidence or market data for the estimated costs and capacity of current embedded generation, existing load control, new load control and new generation.[5] Something that is also a concern is that new load control and new generation seem to take effect immediately and are treated the same was as existing measures even though they are 'new'.[6]
- an apparent lack of evidence or market data to support both the Authority's choice of scenarios for alternatives to transmission investment and its assumptions regarding the elasticity of industrial load.
- the application of almost identical modelling for both the RCPD options (which are all variations of the existing charging arrangements), and the gross MWh charges. The MWh option is a structural change that is likely to:
  - alter industrial user demand for electricity by more than is suggested by the Authority's estimates of industrial demand elasticity
  - completely alter the incentives for using the transmission network during peaks and as such change the requirement and location for grid assets potentially stranding some assets and requiring additional investment in other areas.
- in particular the analysis of the effect of a full or partial gross MWh charge is missing the following:
  - estimate of the increased investment in the transmission network after the incentive to avoid use of the grid in peak periods is removed. At the moment the estimate is based on the Authority's guess of what embedded generation and load control has been put in place.[7]
  - potential for much larger fall in industrial demand than is suggested by the elasticity assumptions which indicates to us that the deadweight loss is under-estimated in the CBA.
  - consideration of the economic costs of lower production by industrial consumers in response to the gross MWh charge.
  - potential for stranding, or under use, of assets and consideration of the risk of stranding of Transpower and EDB assets configured for industrial users.

[5] Although the fixed and variable costs for each generation and load control options are the same for all region s, the capacity of each of the options as percentage of the peak regional load varies from one region to another.

[6] Appendix I Table 14 indicates the new back-up generation will 'in year 5-15' but the spreadsheet calculations for the CBA benefits of each option do not seem to use a different set of calculations for the benefit discount rate for these benefits.

[7] By admission the Authority and Transpower regard N = 12 as a strong mechanism for suppressing regional peak demand and as such it is possible to imagine that 'several hundred' MW of demand could be added to the peak if, for example, a per MWh allocator was chosen. There are grid costs associated with such an increase which must be accounted for in the CBA. They are missing from the CBA that we can see.

42. While we see the CBA as perhaps illustrative for assessing variations in the RCPD regime, due to the lack of information on the generation and load control costs it is not fit for purpose for evaluating the structural shift in charging from RCPD to gross MWh. We discuss three particular concerns below.

Fixed costs

43. The estimated fixed and variable costs of load control appear to us to be unrealistically high. From what we understand about the business processes followed by EDBs and industrial users, we find it difficult to validate either the level of the costs or the methodology used to estimate the benefits from avoiding these costs.

44. We are unsure what the fixed costs of $20 per kW per year for load shedding relate to. If they are true fixed costs associated with operating load shedding tactics then a figure of $20 per kW per year seem to be very high in comparison to the very low fixed costs for operating load control that were indicated to us by industrial users. If on the other hand the fixed costs in the CBA refer to amortisation of the capital cost of existing embedded generation and EDB load control assets, the asset owner faces a write-off once these assets are not required for load control so the fixed costs are not avoided.

45. Either way, the CBA seems to overstate the benefit from avoided fixed cost. To illustrate our concerns with this issue we have calculated the NPV with the fixed cost of demand control set to zero for each of the Authority options – in Table 3 below. Here we describe the outputs from the CBA with the Authority assumption of $20/kw for fixed costs and the alternative NZIER assumption of $0/kw.

Table 3 CBA fixed cost assumption comparison (NPV $m)

	Scenario									
	Base		A		B		C		D	
	EA	Alt.	EA	Alt.	EA	Alt.	EA	Alt.	EA	Alt.
N=100 all Regions	**5**	*2*	**6**	*3*	**6**	*3*	**17**	*13*	**10**	*7*
N=500 all Regions	**3**	*-18*	**24**	*3*	**24**	*3*	**46**	*24*	**47**	*26*
50:50 Gross MWh, Status Quo	**4**	*0*	**12**	*9*	**30**	*27*	**49**	*46*	**43**	*40*
LRMC + Gross MWh	**-88**	*-106*	**-61**	*-79*	**4**	*-14*	**48**	*30*	**48**	*30*
Gross MWh	**-108**	*-133*	**-71**	*-96*	**2**	*-24*	**53**	*28*	**58**	*32*

Source: NZIER analysis based on Authority spreadsheet

46. We estimate that reduction of the avoided fixed cost from $20/kW/year down to $0/kW/year for existing generation and all load control options lowers the CBA for all options by a fixed amount:

- for the N=100, 50:50 Gross MWh and the Status Quo scenarios, the estimated NPV is approximately $3m lower for each option.

- for the N=500, LRMC + Gross MWh and Gross MWh scenarios, the estimated NPV is about $20 to $30m lower.

Value of lost load

47. We have commented previously on the estimation of the value of lost load (VoLL). Admittedly, some users may attach a high value to load that is lost without warning and that loss affects production processes. However, we suggest that this valuation does not apply for industrial users where the approximate timing of the peaks can be predicted and their load actively managed.

48. To illustrate the impact of the VoLL assumption (Authority range is $500 to $3,000/MWh) we have calculated the NPVs for the Authority scenarios at a lower VoLL of $300 per MWh which is the SRMC of generation assumed in the Authority analysis. The results of this calculation are shown in the following Table 4. Here we describe the outputs from the CBA with the Authority assumption of $500 to $3000/MWh for VoLL and the alternative NZIER assumption of $300/MWh.

Table 4 CBA VoLL assumption comparison (NPV $m)

	Scenario									
	Base		A		B		C		D	
	EA	Alt.	EA	Alt.	EA	Alt.	EA	Alt.	EA	Alt.
N=100 all Regions	**5**	*-6*	**6**	*-6*	**6**	*-6*	**17**	*0*	**10**	*-1*
N=500 all Regions	**3**	*-24*	**24**	*-3*	**24**	*-3*	**46**	*13*	**47**	*20*
50:50 Gross MWh, Status Quo	**4**	*-15*	**12**	*-6*	**30**	*12*	**49**	*25*	**43**	*25*
LRMC + Gross MWh	**-88**	*-114*	**-61**	*-86*	**4**	*-22*	**48**	*17*	**48**	*23*
Gross MWh	**-108**	*-135*	**-71**	*-98*	**2**	*-25*	**53**	*21*	**58**	*31*

Source: NZIER analysis based on Authority spreadsheet

49. We estimate that reduction of the VoLL from the Authority range down to $300/MWh for all load control options lowers the CBA for all options as follows:

    - for the N=100 all Regions, the 50:50 Gross MWh and the Status Quo scenarios, the estimated NPV is $10 to $20m lower for each option.
    - for the N=500 all Regions, LRMC + Gross MWh and Gross MWh scenarios, the estimated NPV is about $20 to $30m lower.

50. These sensitivities are a concern. In combination they have a material impact on the outcome of the CBA and are large in comparison to the overall NPV of the scenario options. For us they highlight the scale of the CBA sensitivity to changes in the RCPD and suggest considerable caution in making a decision to change the allocation basis of the interconnection charge.

Elasticity estimate

51. The Authority CBA includes an estimate of the 'dead weight losses from less electricity being consumed in response to a gross MWh charge.

52. The Authority estimates that in the base case and case A there is a larger component of more elastic load (9000 GWh of consumption that has an elasticity of -1.5) while in the remaining cases B to D the load is smaller and less elastic (7000 GWh of consumption and the elasticity falling to -0.35). These elasticities indicate the percentage decrease in the volume of electricity demanded by industrial users falls if prices are increased by 1 percent.

53. The Authority does not provide a rationale for the combination of loads and elasticities in its scenarios. Our discussions with industrial users suggest that the demand for electricity could fall by more than 1.5 percent if prices increased by the amount implied by the application of a gross MWh charge.

2.1.6. NZIER assessment of N=100 and options

54. In the same manner as for the Authority 2012 TPM paper we again regard the inefficiencies described in this consultation paper as theoretical and illustrative rather than representative of the system and definitely not definitive enough to base a decision to change transmission pricing. Many of the inefficiencies are largely assertions that use examples considered through the narrow perspective of grid efficiency, as opposed to using broader costs and benefits that are based on real world evidence to identify and quantify the problems.

55. To their credit the Authority is asking the right questions about what happens in the real world and whether their assumptions regarding problems and solutions with transmission pricing hold up, but in our view they are going about the task in the wrong order. What happens in the real world should come ahead of determining the existence and nature of a problem and the development of solutions.

56. We describe our assessment in two parts as follows.

RCPD N = 100 proposal

57. If the Authority are firm with their objective that a peak demand charge is required to efficiently defer transmission investments then the status quo or the proposed variation N = 100 are the better ways to go.

58. For us the proposal to change the UNI and USI to N = 100 may not end up to be a major issue for grid users. Our analysis of the impacts has revealed that the adjustments to RCPD in these regions will probably result in only a small reallocation of transmission revenue across regions. The impacts are small enough compared to current RCPD charging that we wonder whether the change will have any effect on grid efficiency at all. Responses to the Authority questions will better inform this issue.

59. Our analysis of peak and off-peak demand data in the existing N = 100 regions has also revealed that off-take varies across trading periods by only a small amount, suggesting that total load shedding by industrial customers is probably less than 1% of peak.

60. The existence of benefits from the change to N = 100 is therefore dependent on whether the assumptions in the Authority assessment of the costs and benefits makes sense. We have discussed above where we see difficulties with the structure of, and assumptions within, the CBA but in the context of making a decision to agree to the Transpower variation. We suggest the following as persuasive to the Authority leaving the status quo in place.

- We understand that there is little to no cost for industrial users when operating their demand management resources. This is especially the case for co-generation which runs from production by-products such as waste heat. We also understand that this holds for both N = 12 and N = 100 which leaves us concerned that a major part of the Authority 'benefits from avoided fixed costs' in their CBA is not a valid assumption and, depending on other assumptions, the proposed variation may result in dis-benefits.
- The Authority note in passing that they have identified better solutions to the problems that they see with the current TPM but they stop short of describing what these solutions are. Given that we are of the view that any costs and benefits from the change to N = 100 will be very small we wonder whether changes should be made to any part of the current TPM ahead of the Authority's own TPM package – due shortly.

Use an MWh allocator proposal

61. This option has been proposed before – by TPAG and by the Authority as part of their beneficiary pay consultation in 2012. For us a flat tax charge like the MWh has both benefits and downsides that are generally understood and accepted so we will avoid going over old ground here.

62. For us any proposal to use an MWh allocator is a major change rather than a small 'variation' and will have wide and material impacts from the wealth redistribution that comes with it.[8] Several aspects of this option warrant attention. Overall we see obvious and major difficulties if an MWh allocator is preferred under this variation but is changed later when the Authority's own proposal for transmission pricing is revealed.

63. In this regard we have argued before that it is better to wait and see what the final TPM looks like, how all the moving parts will fit together and especially whether the costs and benefits of the final proposal could deliver a positive outcome. We maintain that this is still the way to go.

64. We also have a number of specific issues with the MWh proposal as follows.

65. This option will likely result in a major shift in demand response from the large wealth transfer between distribution networks and other users of the

8 The wealth effects are made up of a number of elements – distribution impacts from the reallocation of interconnection charges, the stranding of embedded generation and load control assets and the effects of unpredictable peaks on consumers.

transmission grid. We are thinking here that the business viability of some industrial grid users could come under threat from this approach, or at least their electricity consumption patterns will change in a step function manner. If we are right in our thinking then the elasticity assumptions in the CBA are simply not relevant to the analysis of this option.

66. The impacts of the assumptions in the CBA for this option (we include the 50:50 option here also) result in large swings between costs and benefits. We urge caution because of the potentially large costs involved with getting assumptions wrong.

67. We also have concerns that the welfare losses (DWL in the Authority CBA) comes with a very narrow view of the economic impacts of introducing an MWh charge. The impacts will be wider than just the loss from the unused electricity. Reduced electricity consumption because of the use of an MWh allocator or the exit of a major user will have flow on impacts including a reallocation of grid costs across remaining users. Any CBA analysis of this option needs to factor the wider impacts such as these.

68. The CBA analysis does not include any dynamic effects of the MWh option. It takes a short term static view. This concerns us because we are looking at a shift from a well understood peak demand charging regime to a 'not well understood' flat rate charge where peaks matter less. Because alternative behaviour – the counterfactual under this option, is by definition not known, we see difficulties making assumptions within the CBA as what the alternatives here could be.

69. Also the Authority CBA does not appear to:

- be explicitly linked to Transpower forecasts for grid investment
- provide a rationale for the 'probability weights' used to combine the high and low cost grid investment options or the related assumptions about demand
- comment on the asymmetric investment risk between long-lived transmission assets and existing embedded generation or load shedding assets.

3. Our views overall

70. In the past we have made our views clear regarding the Authority (and in this case Transpower) making running changes to the way transmission revenue is allocated. We repeat some of those views below because they remain relevant and material to the consultation on this particular TPM variation.

71. The question as to which transmission charging approaches are more or less efficient is not a simple matter to answer. The trick is to identify who benefits from grid investments – simple in theory because an investment should be justified and approved if its benefits exceed its costs. Everyone associated with the investment is better off and should be prepared to pay for its costs. This is both a 'fair' approach and one that supports consistent investment incentives. It is efficient in that it recognises the different value of grid investments at different locations and to an extent it mimics the outcomes from voluntary investment agreements while dodging the potential for parties to free ride on an investment.

72. This is far easier to do for new investment rather than for grid components that were built many years ago. Here beneficiary identification using the 'what would the grid look like with and without a particular component' would be made very difficult through having to unravel the many adjustments made after a particular component was built.

73. The temptation is therefore to avoid all that subjective analysis of investments over time and just share the costs across all consumers (generally with an overall MWh charge or just in a region). Unfortunately this eliminates the incentives to invest in alternatives to transmission grid expansion, such as cogeneration and distributed renewable generation. Uniform regional cost recoveries can provoke substantial opposition to (possibly) important grid projects because parties perceive that they will end up with charges that are way in excess of the benefits that they receive.

74. Thus the structure and mechanics of charges to recover transmission investments is important to everyone, and especially important to those parties who invest in their own generation with those grid charges as their backdrop. They make their investments based on the transmission charges that they face and on their long term outlook regarding the risks their investments are exposed to.

Demand is reshaping itself

75. We commented earlier on how demand side dynamics are changing as a result of a number of influences and that these changes are set to continue and develop in scale and scope. The regulatory system needs to respond accordingly.

76. Declining demand growth for energy, climate change concerns, strong growth of renewable local generation of electricity, energy storage systems and demand management as well as the use of smart technology in the operational management of grids have all combined to jump start what is now regarded as

potentially the most profound changes to the energy industries since the initial development of the networks. These changes appear to be neither short term nor cyclical. They are structural, long term and are changing the economics of this energy 'eco-system'. It will get more complex and messy.

Defining the problem

77. We remain concerned with how the Authority is appearing to redefine the problems with the current TPM. Changes to demand for grid supplied electricity now makes transmission investment less of an issue which is to be expected when the grid has been expanded and demand is expected to remain flat for some time to come. The Authority does recognise these changes but they still describe their examples of the problems in absolute terms. Relativities are largely missing.
78. In a similar manner the problem definition takes a narrower view of the issues than before and uses quite specific examples of potential operational inefficiencies. For example they look in great detail at the potential for NZAS to avoid increased summer production because of RCPD charges but brush over how and whether distributed and co –generation are material problems when thinking about transmission charges. To us there appears to be a lack of coherency as to the nature and definition of problems over time and of how they are handled in this new paper.

Inefficient investment and use of the grid

79. The use of a flat MWh charge to avoid difficulties associated with complex allocation arrangements offers a simplicity that is deceptive.
80. Simplicity is a two edged sword. To deal with the core issues conceptually, there is benefit in identification and focus on what matters overall, however on the other hand it is the detail within the TPM that makes for potential difficulties, regardless of the version of the TPM that is in place.
81. We believe that the Authority is considering efficiency (of the overall electricity system) at too high of a level. Their approach over-simplifies both the issues emanating from the broader economics of the transmission grid and the importance of non-TPM drivers of business decisions made by generators and electricity users.

4. Responses to the Authority

To give our advice focus and be able to provide input on the matters that we think need attention, we use the Authority's question structure to submitters.

Question 1: Do you have any comments on the part of the problem definition that relates to the interconnection charge incentivising a higher level of demand response than is efficient?

Transpower has identified the potential for the theoretical over-signalling of the value of embedded generation or load shedding. However neither Transpower or the Authority have been able to identify evidence of the capacity or cost of avoiding transmission peaks to translate this theoretical argument into a reliable estimate of 'inefficient avoidance' of use of the grid.

NZIER have been consistently of the view that the problems the Authority (and now Transpower) perceives as being real issues, that are attributable to the TPM, have not been adequately defined or evidenced. While these three attempts have redefined the drivers of the 'problems', to us they do not appear to have led to either a stronger quantitative evidence base or a convergence of the estimate of the costs and benefits of the current TPM regime.

The Authority and Transpower seem to have a high level and broad/sweeping view of 'demand side responses' to transmission pricing in general and the negative impact that these assumed responses have on grid efficiency. They do not consider the more detailed logic and economics of demand side activities that have an impact on grid and system use – such as use production waste heat to fuel own (co-) generation; or use local geothermal or solar resource to generate local electricity.

We have four broad areas of concern with the CBA:

- An apparent lack of evidence or market data for the estimated costs and capacity of current embedded generation, existing load control, new load control and new generation. Also something of a concern is that new load control and new generation seem to take effect immediately and are treated the same was as existing measures even though they are 'new'.
- An apparent lack of evidence or market data to support both their choice of scenarios for alternatives to transmission investment and their assumptions regarding the elasticity of industrial load.
- The application of almost identical modelling to both the RCPD options (which are all variations of the existing charging arrangements), and the gross MWh charges. The MWh option is a structural change that is likely to:
  - alter industrial user demand for electricity by more than Is suggested by the Authority's estimates of industrial demand elasticity
  - completely alter the incentives for using the transmission network during peaks and as such change the requirement and location for grid assets potentially stranding some assets and requiring additional investment in other areas.
- The analysis of the effect of a full or partial gross MWh charge is missing the following:

- Estimate of the increased investment in the transmission network after the incentive to avoid use of the grid in peak periods is removed. At the moment the estimate is based on the Authority's guess of what embedded generation and load control has been put in place.
- Potential for much larger fall in industrial demand than is suggested by the elasticity assumptions which indicates to us that the deadweight loss is under-estimated in the CBA.
- Consideration of the economic costs of lower production by industrial consumers in response to the gross MWh charge.
- Potential for stranding, or under use, of assets and consideration of the risk of stranding of Transpower and EDB assets configured for industrial users.

While we see the CBA as perhaps illustrative for assessing variations in the RCPD regime, due to the lack of information on the generation and load control costs it is not fit for purpose for evaluating the structural shift in charging from RCPD to gross MWh.

The Authority, by admission, regard the CBA analysis as illustrative (we do as well), rather than asserting that any of their assumptions or options reflect a possible or probable future outcome. Despite this strong caveat the Authority do rank each of the charging options from Table 2 above based on their net present value estimated from the Authority's CBA assumptions and conclude that:

- the status quo (N = 12) is not preferred under any of their assumptions
- the proposed variation (N=100) is preferred if you accept their assumptions for the base case situation
- the other charging options in Table 2 may be preferable if alternative assumptions are considered (Cases A to D).

The Authority does not express a view on the relative likelihood of the scenarios. We note that the average net present value of the Authority's benefits for each of the options is low (0.2 to 0.5 percent) relative to the net present value of the interconnection cost indicating that at best the average potential efficiency benefit will be very small. The options involving a gross MWh charge and an LRMC/gross MWh charge are highly sensitive to the choice of scenario and generate an average cost of about 0.2 percent of the net present value of the interconnection cost.

It seems to us that the Authority do not believe that their CBA provides them with enough precision to base a decision on – we agree with this conclusion but we go further in the our response to questions 4 to 8 and suggest that the cost benefit analysis itself does not have a strong enough evidence base to indicate the likely outcome of the proposed variation.

Question 2: Do you have any comments on the part of the problem definition that relates to the RCPD allocation deterring some consumers from increasing consumption in the summer months?

We agree with the problem definition proposed by the Authority in this regard and the proposed solution.

Question 3: Do you have any comments on the part of the problem definition that relates to the treatment of reverse flows?

We accept the theoretical definition of the problem but we are not aware of examples of reverse flow. Accordingly we do not have any comment on the materiality of the problem.

Question 4: In your view, how would participants change their behaviour if the RCPD allocation used N=100 in the UNI and USI regions? What would be the economic costs and benefits of this change in behaviour?

If the Authority are firm with their objective that a peak demand charge is required to efficiently defer transmission investments then the status quo or the proposed variation N = 100 are the better ways to go.

For us the proposal to change the UNI and USI to N = 100 may not end up to be a major issue for grid users. Our analysis of the impacts has revealed that the adjustments to RCPD in these regions will probably result in only a small reallocation of transmission revenue across regions. The impacts are small enough compared to current RCPD charging that we wonder whether the change will have any effect on grid efficiency at all. Other responses to the Authority questions will better inform this issue.

Our analysis of peak and off-peak demand data in the existing N = 100 regions has also revealed that off-take varies across trading periods by only a small amount, suggesting that total load shedding by industrial customers is probably less than 1% of peak.

The existence of benefits from the change to N = 100 is therefore dependent on whether the assumptions in the Authority assessment of the costs and benefits makes sense. We have discussed earlier where we see difficulties with the structure of, and assumptions within, the CBA but in the context of making a decision to agree to the Transpower variation, we suggest the following as persuasive to the Authority leaving the status quo in place.

- We understand that there is little to no cost for industrial users when operating their demand management resources. This is especially the case for co-generation which runs from production by-products such as waste heat. We also understand that this holds for both N = 12 and N = 100 which leaves us concerned that a major part of the Authority 'benefits from avoided fixed costs' in their CBA is not a valid assumption and, depending on other assumptions, the proposed variation may result in dis-benefits.
- The Authority note in passing that they have identified better solutions to the problems that they see with the current TPM but they stop short of describing what these solutions are. Given that we are of the view that any

costs and benefits from the change to N = 100 will be very small we wonder whether changes should be made to any part of the current TPM ahead of the Authority's own TPM package – due shortly.

Question 5: In your view, how would participants change their behaviour if the RCPD allocation used N=500 in all four regions? What would be the economic costs and benefits of this change in behaviour?

Our assessment is that the increase in N=500 does not deliver material additional benefits above that of moving to N=100. As noted in our response to the proposal for N=100 we think the Authority has over-estimated the fixed cost and SRMC/VoLL for embedded generation and load shedding and therefore we are sceptical that the Authority's estimated benefits will be realised.

Question 6: In your view, how would participants change their behaviour if the interconnection charge was a per-MWh charge on gross load? What would be the economic costs and benefits of this change in behaviour?

For us any proposal to use an MWh allocator is a major change rather than a small 'variation' and will have wide and material impacts from the wealth redistribution that comes with it. Several aspects of this option warrant attention. Overall we see obvious and major difficulties if an MWh allocator is preferred under this variation but is changed later when the Authority's own proposal for transmission pricing is revealed.

In this regard we have argued before that it is better to wait and see what the final TPM looks like, how all the moving parts will fit together and especially whether the costs and benefits of the final proposal could deliver a positive outcome. We maintain that this is still the way to go.

We also have a number of specific issues with the MWh proposal as follows. This option will likely result in a much larger shift in demand response from the large industrial users than from the elasticities assumed by the Authority. We are thinking here that the business viability of some industrial grid users could come under threat from this approach, or at least their electricity consumption patterns will change in a step function manner. If we are right in our thinking then the elasticity assumptions in the CBA are simply not relevant to the analysis of this option.

The Authority's own CBA estimate of the efficiency gain or loss from this option varies widely across the grid investment/industrial demand scenarios analysed by the Authority. Because of this volatility we urge caution because of the potentially large costs involved with getting assumptions wrong.

We also have concerns that the welfare losses (DWL in the Authority CBA) comes with a very narrow view of the economic impacts of introducing an MWh charge. The impacts will be wider than just the loss from the unused electricity. Reduced electricity consumption because of the use of an MWh allocator or the exit of a major user will have flow on impacts including a reallocation of grid costs across remaining users. Any CBA analysis of this option needs to factor the wider impacts such as these.

The CBA analysis does not include any dynamic effects of the MWh option. It takes a short term static view. This concerns us because we are looking at a shift from a well understood peak demand charging regime to a 'not well understood' flat rate charge where peaks matter less. Because alternative behaviour – the counterfactual under this option, is by definition not known, we see difficulties making assumptions within the CBA as what the alternatives here could be.

Also the Authority CBA does not appear to:

- be explicitly linked to Transpower forecasts for grid investment
- provide a rationale for the 'probability weights' used to combine the high and low cost grid investment options or the related assumptions about demand
- comment on the asymmetric investment risk between long-lived transmission assets and existing embedded generation or load shedding assets.

Question 7: In your view, how would participants change their behaviour if the interconnection charge was a 50-50 mix of the status quo and a per MWh charge on gross load? What would be the economic costs and benefits of this change in behaviour?

In our response to questions 4 and 6 above we have summarised our concerns with the Authority's CBA of the change to N=100 and a gross MWh charge. These concerns also apply to the 50:50 hybrid. In short we believe Authority has over-estimated benefits of the shift to N=100 and under-estimated the elasticity of industrial demand.

The combination of gross MWh charge and a shift to N=100 also combines two fundamentally different charging regimes. (The RCPD approach allocates costs on the basis of user contribution to peak load and seeks to influence the requirements for peak capacity, while the gross MWh charge is a flat tax that does not consider peak loads.) We cannot see a good theoretical rationale based on complementing strengths that justify this combination of charging regimes or any evidence of why an across the board 50:50 mix is favoured over other mixes of the two charging regimes. We have little confidence that the 50:50 hybrid would be a durable change to the transmission pricing methodology. Industrial users may interpret the hybrid as a precursor to a move toward all of the connection costs being recovered from gross MWh charge and change their production and investment decisions in anticipation of this change.

Question 8: In your view, how would participants change their behaviour if the interconnection charge was a combination of a regional LRMC-based charge and a per-MWh charge on gross load? What would be the economic costs and benefits of this change in behaviour?

In our response to questions 4 and 6 above we have summarised our concerns with the Authority's CBA of the benefits of reducing the use of embedded generation/ load shedding and a gross MWh charge. These concerns also apply to the LRMC gross MWh hybrid. In short we believe Authority has over-estimated the net benefits from reduced use of load shedding/embedded generation. They have also under-estimated the elasticity of industrial demand and therefore the deadweight loss from a gross MWH charge.

We have little confidence that the LRMC gross MWh charge hybrid would be a durable change to the transmission pricing methodology. Industrial users may interpret the hybrid as as a precursor to a move toward all of the connection costs being recoverd from gross MWh charge and change their production and investment decisions in anticipation of this change.

Question 9: Do you consider that the proposal in Section 4 (i.e. that the RCPD allocation should use N=100 for all four regions) is preferable to the status quo and other options? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.

As discussed in our response to question 1 the benefits of the efficiency gain estimated in the Authority's CBA seems to us to be very small in comparison to the net present value of the interconnection cost. We do not accept that the Authority has provided strong evidence that the proposal to shift to N=100 for all regions is superior to the status quo. However we agree that on the basis of our assessment of the Authtority's CBA, the option to shift to N=100 for all regions is preferable to the other options proposed by the Authority.

Question 10: Do you consider that the proposal in Section 4 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?

No, as discussed in our responses to the elements of the proposal in Section 4 we do not agree that the Authority's CBA provides evidence that any elements of the proposal will deliver benefits to consumers.

Question 11: Do you have any comments on the drafting of the proposal in Section 4, which is included in Appendix B?

We do not support the proposed change but do not have any comment on the wording to implement the change.

Question 12: Do you consider that the proposal in Section 5 (the 'amended RCPD CMP' component) is preferable to the status quo and other options discussed in Section 5? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.

We support this proposal

Question 13: Do you consider that the proposal in Section 5 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?

We support this proposal

Question 14: Do you have any comments on the drafting of the proposal in Section 5, which is included in Appendix B?

No comment

Question 15: Do you consider that the proposal in Section 6 (the 'RCPD quantity adjustment provision' component) is preferable to the status quo and other options discussed in Section 6? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.

No comment

Question 16: Do you consider that the proposal in Section 6 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?

No comment

Question 17: Do you have any comments on the drafting of the proposal in Section 6, which is included in Appendix B?

No comment

Question 18: Having regard to the Code amendment principles, should the Authority proceed with the 'amended RCPD CMP' component, the 'RCPD quantity adjustment provision' component, both or neither?

We support this proposal

Question 19: Do you consider that the proposal in Section 8 (regarding reverse flows) is preferable to the status quo and other options? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.

No comment

Question 20: Do you consider that the proposal in Section 8 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?

No comment

Question 21: Do you have any comments on the drafting of the proposal in Section 8, which is included in Appendix B?

No comment