Not time to revisit TPAG

Our views on revisiting the TPAG majority view in light of the current TPM proposal

NZIER report to MEUG

March 2013

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Authorship

This report was prepared at NZIER by John Stephenson.

It was quality approved by David de Boer.

Version - final

Our recommendation

This report provides our assessment of the relevance of the Transmission Pricing Advisory Group's views in light of the Electricity Authority's recent Transmission Pricing Methodology proposal and submissions by parties on that proposal. We also provide limited comments on particular submissions.

You have asked us to advise you on the merits of revisiting the majority view expressed by the Transmission Pricing Advisory Group.

Our view is that you (and the Electricity Authority) should disregard calls for reconsideration of aspects of the TPAG report.

We agree with Meridian (header to paragraph 15) in saying that "the status quo is no longer an option". The TPAG majority view was essentially status quo plus.

The information provided by the Authority in making its proposal has significantly undermined the case for the TPAG majority view – a view which we have always been sceptical of because it represented certain consumer cost for uncertain consumer benefit.

We were previously of the view that TPAG did not adequately evaluate alternatives or demonstrate that its alternative charge would be net beneficial. Current market conditions would seem to reinforce our view. Moreover the Authority's proposal is something of a game changer in that it could resolve TPAG's concerns around HVDC charges and minimise adverse impacts on consumer welfare. While we see merit in the proposal we would point to the short comings and risks with many aspects of the methodology that we reported to MEUG in February 2013.

What has changed?

1. Two things have changed since TPAG came up with its discussion paper and recommendations on transmission pricing which must alter any assessment of the TPAG majority view:

   - the empirical basis for TPAG's assessment is no longer valid due to flat demand growth and a significant shift in generation investment intentions
   - the Authority has proposed a pricing alternative which appears to offer greater benefits to consumers than the TPAG majority view.

2. Recall that TPAG's majority view was that HVDC charges should be shifted to consumers' transmission charges using the current RCPD allocation method but with charges being phased in over 10 years to avoid any perverse impacts from a sudden and large wealth transfer.
3. One of the key judgements in the TPAG majority view was that shorter term costs to consumers from a wealth transfer from consumers to generators would be offset by longer term reductions in wholesale electricity prices due to increased investment in lower priced generation in the South Island, where generators currently face HVDC charges. We think this conclusion is not realistic.
4. Another key judgement by the TPAG majority viewers was that a postage stamp charge is the most efficient way to deal with charges for transmission assets that are sunk. The Authority's proposal shows that there may be better alternatives and in any case the status quo remains a better option to TPAG.
5. Elements of the analysis used by TPAG were quite out-dated even then. A key example of this was demand assumptions which were far too high. Demand growth is the central issue for evaluating consumer benefits and yet it was overlooked in favour of careful (albeit speculative) analysis of generation investment intentions.
6. The TPAG report considered generation investment inefficiencies as being the key issue in transmission pricing. The current flat demand growth environment shows that demand side inefficiencies can also matter a great deal.

Low demand growth

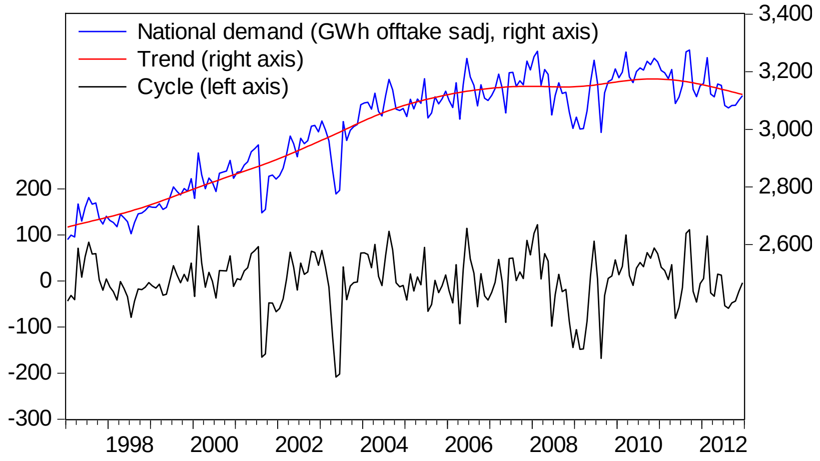
7. The current demand environment has a material impact on TPAG's assessment.
8. TPAG majority view was predicated on accelerated investment in low (but not lowest) cost generation. This is assumed to provide consumers with the benefit of lower long run prices as the long run marginal cost of supply declines. The numbers were not large – in the order of $16 million (investment efficiency).
9. Since the TPAG report, investment plans have been put on hold and it looks unlikely that the investments described by TPAG will come to fruition within

a timeframe which is meaningful to consumers. This suggests to us that their estimates are on the high side.

10. TPAG's assumptions about demand growth, which raises benefits and helps to bring forward investment, looks increasingly suspect on recent events.
11. TPAG's analysis assumed demand growth starting at 2% per annum in 2013 and declining gradually thereafter (to reflect slowing population and GDP growth) to 1.5% per annum – an average of 1.7% per annum. Average growth historically has been 1% per annum since 1998. It is very hard to see how this growth rate would increase much at all in coming years, not least because of higher transmission charges.
12. In the past four years annual demand growth has been negative, averaging -0.2%. This is not entirely related to slow economic growth given that GDP expanded at a compound average growth rate of 1.5% between 2004 and 2012 while electricity demand grew by 0.1% on average.
13. The likelihood of a continued low growth environment for electricity demand is high. It is surprising that the TPAG analysis did not reflect trends evident at the time but, in any case, those trends are now abundantly clear.
14. The TPAG analysis was more comprehensive than we would want to replicate here but we note that a lowering of TPAG's demand assumptions to 1% per annum lowers the central NPV estimates of benefits of the TPAG majority view (excluding short term wealth transfer costs) from $16 million to a net present value of $2.1 million.

Figure 1 Demand growth slow for some time

Monthly energy demand, seasonally adjusted



Source: NZIER

15. Our views and concerns are also reflected in the submission from the New Zealand Geothermal Association (p.5) which notes that generation development opportunities are, in the near term, dictated by site-specific considerations (not HVDC prices) and are dominated by resources in the North Island:

> *"…the next 20,000GWh of capacity addition will be dominated by geothermal and wind developments…"*

16. The submission goes on to say that:

> *"As there has been essentially no load growth in New Zealand since 2007 and, prior to that, generation growth to meet load growth was at about 700GWh per year, then a 20,000GWh horizon represents over 30 years of new generation projects (or 10,000GWh represents 15 over years). It is only after this period that TPM might have a significant effect on generation selection, and there will be opportunities for pricing methodology reviews before that."*

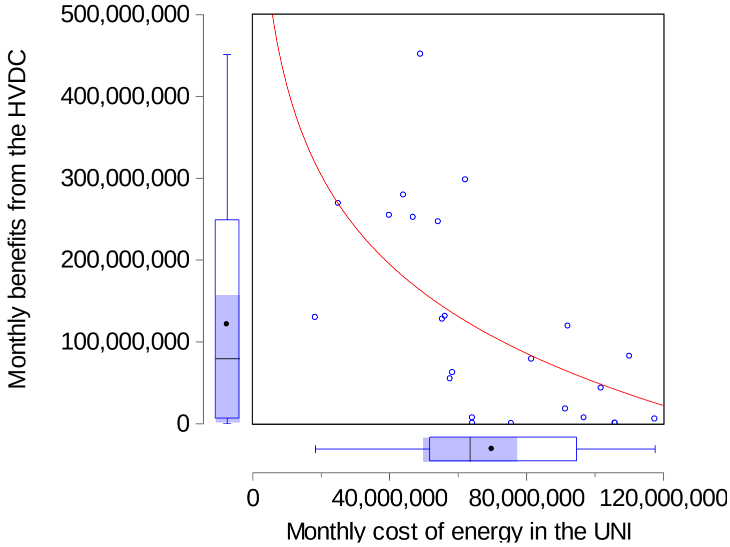
17. These quotes are out of context in the sense that the submission in this case appears concerned that generators cannot respond and transmission charges should be levied on those who can respond – in this case consumers. However, as other submissions point out, any reduction in demand due to rising transmission prices would be a reduction in consumer benefits and would be inefficient.
18. It is nonetheless the case that the efficiency gains and lower longer run prices expected to arise under the TPAG majority view have drifted further out and have become even less certain than they once were. Reductions in consumer welfare from a shift to a "postage stamp transition" would, in contrast, be certain and immediate.

Insights from the new alternative

19. The Authority's proposal is something of a game changer with respect to the TPAG views. It shows that:
    - evaluating beneficiaries of the HVDC is entirely feasible – TPAG wasn't sure if this could be done
    - benefits change over time, sometimes significantly
20. The Authority's proposal is of course broader than the HVDC, but HVDC costs are the relevant ones when considering the TPAG majority view.
21. It is also clear that tailoring transmission charges to changing benefits over time improves the welfare of consumers. This raises a question about how much consumer benefits might increase over the long term. We have not been able to analyse this in sufficient detail but we believe this is a crucial question for the Authority to address as (we strongly suggest) it reconsiders its cost benefit analyses.
22. An as yet under-analysed aspect of the Authority's proposal is that it has an inbuilt price-discrimination mechanism which sees wholesale electricity prices negatively correlated with transmission charges – for the majority of consumers. This situation results from the fact that benefits consumers' receive from transmission come in large part from the ability to access lower priced energy. For most consumers, benefits are lowest when prices are high.

Figure 2 Benefits fall when prices are high

Upper North Island (UNI), 2010-12 data, 2015/16 interconnection revenue

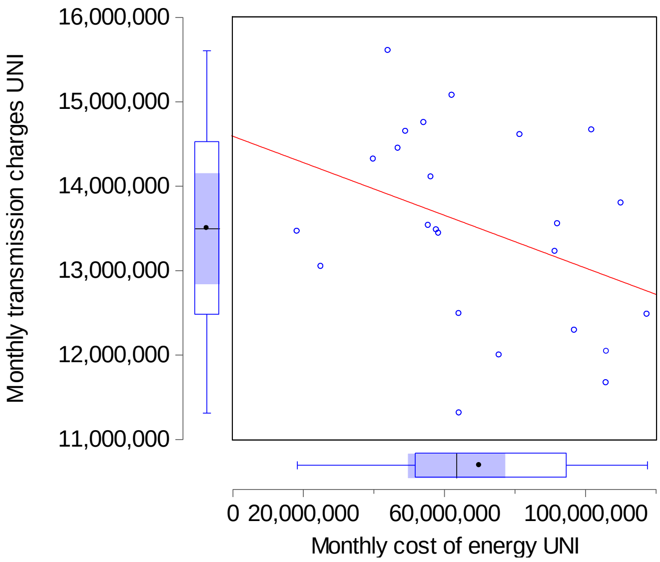


Source: NZIER

23. Actual charges that transpire under the Authority's proposal will not entirely reflect benefits due to the proposed caps on half hourly charges and the use of RCPD to allocate the residual. Charges under their proposal will, however, be a much better reflection of benefits than the TPAG majority suggests.
24. Indeed, the 'cat is out of the bag' with respect to the inadequacy of both the TPAG majority view and the status quo. The Authority's vSPD modelling very clearly shows that to levy a charge on all consumers (via RCPD) to recover the costs of the HVDC would see some consumers pay much more than they benefit. Moreover, this is likely to be most significant during periods when prices are high and consumers can ill afford the cost of a blunt coincident peak demand charge.
25. This can be seen in Figure 2 where, in some months, benefits are approaching zero while energy costs are high. An RCPD based charge on consumers for the HVDC, as envisaged under a "Postage stamp transition", means an invoice will arrive regardless.

Figure 3 Higher energy costs = lower transmission charges

Upper North Island (UNI), 2010-12 data, 2015/16 interconnection revenue

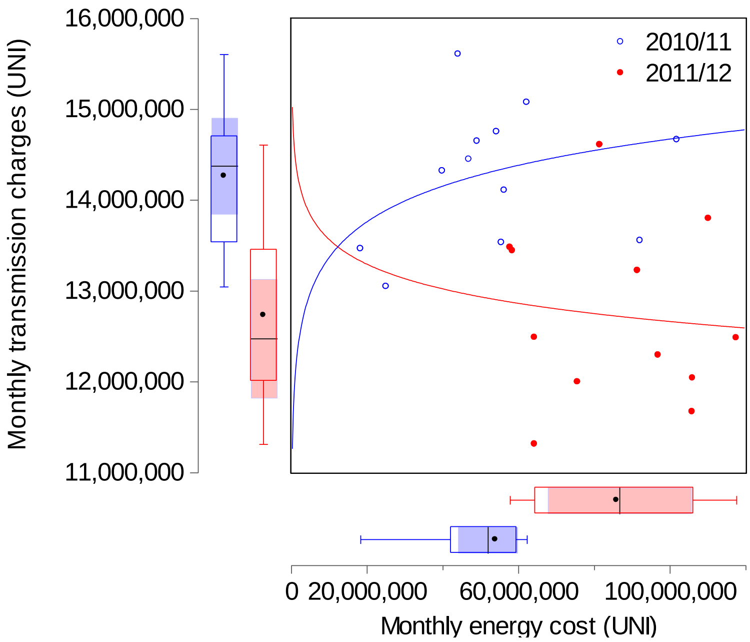


Source: NZIER

26. The Authority's pricing proposal on the other hand inherently accounts for changing demand conditions (see Figure 4).

Figure 4 Actual charges vary by market conditions

Upper North Island (UNI), 2010-12 data, 2015/16 interconnection revenue



Source: NZIER

27. Note that while figure 3 shows aggregated two year data, figure 4 describes the outcomes for each year – reflecting dry and wet conditions in the South Island.
28. We would also point out that under a TPAG style TPM the material welfare losses associated with major investments such as the NIGUP, which we described in our February report, would likely not be identified and would remain locked into future consumer charges.[1]

[1] We estimate these welfare losses at NPV $111m over 3 years – see paras 63 – 68 of our February 2013 report to MEUG.

Our reactions to submissions

29. We do not attempt to cover all the material that has emerged from submissions but rather we provide comments on those matters that emerged as the drivers for change, that is what do parties see as problems.

Some general observations

30. Most submissions see that wealth transfers will be inevitable and are positioning themselves to be winners or to minimise potential losses. While there are plenty of arguments, little by way of analysis or evidence is presented and interestingly there is also little in-principle argument <u>against</u> beneficiary pays.
31. When assembling our issues matrix from the submissions we observed an overwhelming view that there was no material problem with the status quo that needed fixing. Five submitters viewed the current HVDC charges as problematic to a greater or lesser degree and about half of the submitters considered that there were material issues with the wider regulatory arrangements that needed addressing.
32. Most concern with the SPD approach appears to be with submitters' lack of understanding of the detailed mechanics of the proposal, the potential for volatility with SPD charges and with the potential for material competition impacts at retail. We recognise that these views have potential to be important unintended outcomes however we see these issues as matters that will be influenced by the higher-level design of the SPD methodology.
33. Submissions were strong of the view that if the EA was to adopt an SPD based TPM then their proposal needed a major rebuild. We remain of the view that we reported to MEUG in February 2013; that is conceptually the proposal has merit but that material issues need addressing to make it workable. In reviewing submissions we also note a concentration of views regarding a number of material issues, the main one being alleged inefficiencies with how the HVDC is currently charged.

Views on TPAG and HVDC

34. A small number of submissions point firmly to the TPAG majority view as a viable alternative to the status quo. Powerco view the TPAG view as the preferred approach on the basis that the CBA prepared by TPAG stacks up better than the Authority (SPD) version.

> *"If the Authority's prime objective is efficiency, it should roll the HVDC charge into the interconnection charge and recover the total costs using the current allocation method, as recommended by the TPAG. This would be superior to applying the half hourly SPD method every half hour because it would not produce any welfare reducing distortions to wholesale prices."*[2]

[2] P.15 response to question 25.

35. Their analysis of the Authority CBA suggests that the CBA would be negative.[3]
36. Meridian are more firm of the view that the status quo is not an option and that the EA proposal complements the TPAG view that current HAMI charge should be reallocated to deliver a more efficient outcome.[4]
37. MRP state that they can see no compelling evidence that TPAG is not a proportionate and pragmatic solution to the HVDC issues.[5]

> *Mighty River Power can see no compelling evidence in the Authority's analysis to suggest the 2011 TPAG majority proposal was not a proportionate and pragmatic solution to the HVDC issues. It is superior to the Authority's proposal when considered against good practice transmission cost allocation principles and the company continues to support this option.*

38. Contact, however, do not directly support the TPAG view but support the inclusion of HVDC in the overall IC pool.[6]
39. As discussed above, it is clear that the authotity's proposal would see some consumers pay beyond their benefits for the HVDC. TPAG did not have this information at their disposal but now that it is available we are surprised that anyone would suggest revisiting a pricing methodology that has this effect on consumers.
40. Powerco's submission also goes on to suggest that:

> *"… if the Authority wished to apply a beneficiary pays allocation for equity reasons it could split the allocation of the current HVDC revenue approximately 2:1 between the interconnection revenue pool and the HVDC revenue pool (based on the benefit estimates in paragraph 4.3.9 of the consultation paper) and continue to recover the reduced HVDC revenue from South Island generators as at present."*

41. The Authority's analysis (and our analysis above) clearly shows that benefits from the HVDC change over time and reflect market conditions. That being so, how could the Authority justify fixing charges based on a one-off evaluation of benefits. We do not see that they could do so and this is a key reason why the TPAG majority should not be considered as a valid alternative.
42. We suspect that submitters that look favourably upon the TPAG majority view are tending towards the misconception that:

> *"The cost of using these assets is effectively zero and, in any event, does not vary from trading period to trading period, so,*

3 P.20 response to questions 32, 33.

4 Meridian para 15 to 18

5 MRP p13

6 Contact p14 & 15

if there is a consumption response to this charge, the economic impact will be negative".[7]

43. This view is reasonably common and wrong. It may well be that transmission assets are sunk but the cost of using transmission assets is not sunk nor is it zero. Currently, the use of interconnection assets attracts a direct (variable) charge (excluding LCE) in the order of $14 per MWh and ranging between $2 per MWh and $23 per MWh based on volume and time of use (i.e. regional coincident peak). The average charge, under the status quo, is due to rise to nearly $19 over the next few years. There will be a consumption response to this and we agree it will be negative.
44. MRP seems to fall into this trap of assuming zero transmission cost when they argue (p.16)

> *"Given that there would be little benefit in introducing a price signal where there would be little future investment to influence, TPAG focussed on ensuring that the TPM did not create perverse incentives for the inefficient use of the existing sunk transmission assets. TPAG's approach reflects sound regulatory practice."*

45. In fact, if there is no investment to recover then the efficient pricing solution is clearly no interconnection charges, not higher interconnection charges as suggested by the TPAG majority view.

Compatibility with principles

46. In amongst submissions there is one head-to-head comparison that is useful when considering the SPD proposal and a TPAG style alternative.
47. Using a 2010 generalised survey of transmission cost allocation issues, methods and practices published by PJM as a guide, MRP has provided a comparison of the Authority's proposal and that of TPAG's proposal.[8] We note that the PJM report proposes a set of evaluation criteria to promote debate about transmission pricing that MRP see as a useful set of transmission pricing principles.

Understandability

48. TPAG's proposal is considered transparent and easy to understand and resulting in HVDC charges that are stable and well known in advance.
49. The Authority's proposal is considered more complex, hard to understand and resulting in volatile charges. Forecasting will be required to account for hydrology and potential market behaviour, all of which is uncertain.
50. MRP's assessment exhibits a strong degree of status quo bias. Faced with a clean slate on transmission pricing, a consumer interested in investing in plant to expand production would be unlikely to agree that their share of the year's 12 highest peaks of demand in their region (setting aside the net effect after unpredictable movements in loss and constraint rentals), is an

[7] Powerco, p.20 response to question 32.

[8] Pjm – A survey of Transmission Cost Allocation Issues, Methods and Practices. March 10 2010.

especially predictable and non-complex approach which is easy to understand in terms of how it will impact on their delivered costs of energy.

51. Over time, consumers get better at predicting when these peaks will arise and whether it is worthwhile avoiding them. But this comes with learning.
52. What the Authority has proposed is not materially less understandable than the TPAG approach, once we take account of the fact that any new pricing methodology is likely to be less well understood in the first instance.
53. Comparing like with like, and avoiding status quo bias, we find it hard to believe that market participants will not easily understand that their share of HVDC revenue will rise and fall with the direction and magnitude of flows across the HVDC. Indeed they are already attuned to this dynamic because it is a fundamental part of wholesale price determination.
54. For non-HVDC assets it is apparent that charges will be dominated by RCPD and RCPI charges and that these are essentially status quo and thus have the same degree of understandability as the TPAG proposal.
55. Similarly, participants who make decisions based on forecast delivered energy prices already have to account for hydrology and the behaviour of other market participants. There is nothing new here.

Administrative ease

56. We agree with MRP's assessment. There is no doubting that the Authority's proposal is administratively more complex than a simple ex-post calculation of the year's regional coincident peak demands.
57. We don't think this is an especially important consideration, however, as it only matters to the extent that it impacts on:

    - understandability
    - transaction costs faced by the transmission owner
    - scope for errors in the calculation of transmission charges.

58. We think MRP overstates difficulties in understanding the Authority's proposal. Transaction costs are important, but a matter for CBA, in terms of trading off implementation costs against other benefits. Scope for errors could be cause for concern.

Ability to reflect system change over time

59. MRP scores the EA proposal as being moderately compatible with this objective and suggests that the TPAG majority view is also moderately compatible with this objective.
60. This assessment beggars belief. The Authority's proposal rests in part on allocating a share charges based on benefits which reflect wholesale market conditions. These benefits will reflect shifts in system dynamics including fuel constraints (especially hydrology) and seasonal and structural movements in demand and daily peaks.
61. The rest of the Authority's proposal on interconnection charges is essentially the same as the TPAG proposal in terms of its ability to reflect system change with one very crucial exception: the mere existence of a benefit-based transmission charge provides information to the market on how transmission use and benefits are evolving over time. This is

information reflecting system change in terms of the interaction and trade-offs between production and transport costs.

62. Given these considerations it is extremely hard to accept MRP's assessment on this issue.

Stability of transmission rates resulting from cost allocation

63. MRP notes that under the Authority's proposal charges are more volatile and less stable and hard to forecast. This is true, however we don't agree with the assessment that the Authority's proposal has low compatibility with this principle as compared to the TPAG majority view which is considered to be highly compatible with this objective.
64. We assess the Authority's proposal as being moderately compatible with this principle on the grounds that monthly interconnection charges are not especially voilatile and, to the extent that they do move around, this will be welfare enhancing.
65. Second, this principle only matters to the extent that it "may be preferable for those parties responsible for paying for transmission service" and "facilitate more accurate forecasting of future business conditions" (MRP, p. 45). By virtue of a broader tax base,consumers will generally pay lower charges for delivered energy in the short to medium term under the Authority's proposal. Under the TPAG majority view consumers are at all times the only parties responsible for paying for transmission service. It is hard to see how consumers will prefer stable but higher prices to less stable and lower charges.
66. The Authority's proposal will also see transmission charges which are negatively correlated with energy prices. This also implies lower overall costs of delivered energy in the longer term, other things being equal. Again it is hard to see how consumers will, in net, prefer stable higher costs to lower less stable costs.

Short term and long term incentives for generation and load

67. This principle states that cost allocation methods should reinforce rather than run up against existing (efficient) wholesale market signals.
68. MRP says that the TPAG proposal is highly compatible with this because it removes inefficiencies (presumably by being neutral) and has a transitional provision which helps to minimise adverse behaviour which could arise from wealth transfers.
69. The Authority's proposal is deemed to have low compatibility on the grounds that it will:

    - create incentives for generators to alter offers away from efficient costs
    - spreads the current HVDC inefficiencies across both islands
    - reduce incentives for efficient load management by reducing consumers' interconnection charges
    - create incentives to avoid peak injection and reduce investment in peaking plant.

70. We question whether any of these points stack up in terms of working against the existing incentives in the market. However there are two sides to this. One is the way that the Authority proposes to deal with benefit based (SPD) charges and the other relates to proposed coincident peak charges to deal with the residual.

SPD charges

71. In terms of the SPD charges and in respect of incentives to alter offers, we don't think this is a material issue. If generators can alter their offers away from efficient costs then they must have some market power that they are willing to exercise to cause higher prices in the wholesale energy market. If that is the case, this is a problem with the wholesale market not with the Authority's transmission pricing proposal.
72. As discussed in our February report on the Authority's proposal, price setting offers (or those offers in the region of the price setting offer) will not attract a benefit-based charge. There is therefore no common cost to avoid for generators who are competing over the price setting position in the market. Any lifting of price setting offers would have to be reflective of tacit collusion over price setting offers.
73. It is true that inframarginal offers could be distorted as could very high priced offers. However this is already feasible and happens and we don't think it matters a great deal (except to the extent that benefit based charges can be avoided but we do not think there is much or anything that can be done about this that would not unduly compromise the efficiency of the wholesale market).
74. This assessment of the impact of the SPD charge means that it would not have a negative impact on market signals either in terms of offer behaviour or in terms of peak injection and investment in peaking plant. These plants will typically not face material benefit-based charges.

Residual charges

75. The RCPI charges are a slightly different matter. Regarding incentives to reduce investment in and offers from peaking plant, we do wonder what the effect of the RCPI charge will be. We have not explored this in detail but we doubt very much that investment in peaking plant will be retarded by these charges. We expect they will be passed through to consumers if implemented as currently proposed.
76. That being the case these charges will reinforce incentives for consumers to avoid consumption at peak so it is hard to see how the Authority's proposal will reduce incentives for efficient load management.
77. That said, we think the Authority has underdone its analysis on dynamic investment incentives in terms of generation and we believe that this has to be rectified.
78. We also think that the dynamic efficiency benefits from the Authority's proposal will depend crucially on the extent to which residual charges can be made to 'stick'. If they are simply passed through to end consumers then incentives to engage in investment processes will not improve a great deal.

Public good and externality aspects

79. The MRP assessment proposes that the SPD approach is limited and arbitrary because the beneficiary component is less than the full required revenue and that the socialisation of the residual balance (including part to generation) incentivises participants to not invest in efficient investments. We would repeat most of the comments we have made in the section above on inter-temporal incentives again here but would also add that the potential for positive and negative externalities is real under any TPM simply the TPM involves trade-offs between beneficiaries in a measureable economic sense and beneficiaries in a broader social sense. The trick is to recognise the externality risks and be able to accommodate their potential impacts in the design of the TPM.
80. We would also question why the TPAG approach is considered highly compatible with positive externality considerations when a broad postage stamping is considered a sub-optimal approach to pricing and therefore has potential to generate negative outcomes.