Oakley Greenwood

Responses to issues raised on CBA

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1. Background

On the 17 May 2016, the Electricity Authority (Authority) of New Zealand (NZ) released its second issues paper regarding potential changes to the way transmission services are charged for in NZ[1]. In that paper, it proposed to alter the way transmission charges are shared among transmission customers so that charges are linked to the transmission services delivered and the costs involved.

The two key changes that it proposed were to introduce an area-of-benefit charge and a residual charge.

The Authority engaged Oakley Greenwood (OGW) to undertake a quantitative cost benefit analysis (CBA) to support the assessment of the TPM options that were included in its second issues paper, against the counterfactual case[2].

2. Objective

The objective of this report is to examine a number of issues that respondents have raised during the consultation process, and which the Authority has identified as requiring further consideration. In particular, we have been commissioned to provide a written response to each of those issues, as well as undertake any revisions to the CBA modelling that are identified as being required.

3. Caveats

Our brief from the Authority was directed to matters specified by the Authority. Accordingly, in preparing this report, OGW has:

- Only considered the issues identified by the Authority;
- Not reviewed every submission referred to by the Authority in full, rather we have only reviewed those parts of the relevant submissions that were directly related to the issues referred to by the Authority;
- Not considered any other issue raised by submitters that has not been identified by the Authority; and
- Not reviewed every submission that has been provided as part of the TPM consultation process.

1 Electricity Authority, *Transmission pricing methodology: issues and proposal; Second issues paper*, 17 May 2016

2 OGW, *Cost Benefit Analysis of Transmission Pricing Options*, 11 May, 2016

4. The CBA is criticised for assuming the proposal is efficient

4.1. Summary of the issues raised regarding the assumption that the proposal is efficient

The Authority has asked us to consider a number of issues raised by respondents around the CBA assuming that the proposal is efficient. The comments that were provided by the Authority that we were to have regard for include:

- Proposal proxied by an estimate of the LRMC of transmission in each RCPD region, e.g., UNI, LNI, USI and LSI (Transpower);
- Not explained the causal link between proposal and benefits (7.2 of CBA working paper);
- Features of the AoB are not modelled (Trustpower); and
- The Authority has relied solely on 'judgement' in support of the view of dynamic efficiency of the proposal (Powerco).

4.2. Response to issues raised regarding the assumption that the proposal is efficient

The key issue appears to be that there is concern around the fact that we have used an estimate of the LRMC of transmission as a proxy for the prices that would ensue under the AoB proposal, with some respondents concerned that the LRMC is not a reasonable reflection of the features of the AoB charge.

This matter was raised in public forums (e.g. Auckland public forum) where we noted that in the absence of a forecast of the specific individual assets that are to be built in the future and charged for under the AoB, we believe that using the LRMC as a proxy for the cost of the specific assets that will be charged for under the AoB proposal in the future is a reasonable approach to modelling the potential impacts of introducing an AoB charge.

The reason we believe that LRMC is a reasonable proxy for the cost of the specific assets that will be charged for under the AoB proposal in the future is that:

- In terms of future investments, the CBA only assumes there will be benefits in relation to augmentation driven investments. For reasons outlined in the original report, we did not ascribe any benefits to replacement, safety or any other of Transpower's capital expenditure categories;
- From a practical perspective, any calculation of Transpower's LRMC would require it, or the person calculating it, to (a) project out all of Transpower's augmentation projects, and (b) project out the underlying incremental increase in demand driving those augmentation projects, and then divide the NPV of (a) through by (b) to get an estimated annualised cost of providing for that increase in demand[3];

3 This implicitly assumes that the Average Incremental Cost approach to developing the LRMC estimate is adopted. Whilst other approaches such as the perturbation approach differ to this, they still require a forecast of augmentation driven capital expenditure and an underlying growth in co-incident peak demand (being the driver of those augmentation costs).

- The numerator in any calculation of Transpower's LRMC should in theory align very closely with the augmentation assets that would be charged for under the AoB proposal and which we have modelled in our CBA. The difference between the two is that the LRMC calculation converts the augmentation capital program into an annualised amount (e.g., $/KW), whereas in practice, under the AoB proposal, each individual augmentation capex project will be charged directly to the beneficiaries of the asset being constructed over the life of the asset; and
- In short, conceptually, we believe that Transpower's LRMC is a reasonable proxy of the annualised cost of the augmentation assets that will be charged for under the AoB charge[4], particularly given that:
  - the AoB charge would apply to most augmentation assets due to the cut off threshold, and
  - our CBA has only focused on the price signalling benefits as they relate to augmentation assets.

With regard to the statement that we have not explained the causal link between the proposal and the benefits, we believe that the framework set out in Section 7 of our original report ('*Overarching conceptual framework underpinning our assessment*') provides this explanation and describes how we have conceptualised the issue and the economic framework, as well as how we have linked the price signalling aspects of the TPM proposal to our assessment of benefits.

In respect of the comment that the Authority has "*relied solely on 'judgement' in support of the view of dynamic efficiency of the proposal*" we understand the Authority has also had regard for the results of the CBA, and within that analysis, we sought to place a value on these dynamic efficiency benefits. That said, possibly the Authority has made other broader statements that we are not aware of that may give rise to this perception.

5. The assumptions around diesel in the CBA do not reflect the NZ market and significantly inflate the proposal's net benefits

5.1. Summary of the issues raised regarding the diesel generation assumptions

The Authority has asked us to consider a number of issues raised by respondents around the diesel generation assumptions that we have used in the CBA. The comments that were provided by the Authority that we were to have regard for include:

- The diesel generation over the 20 year forecast period does not seem to be consistent with either recent generation patterns or the planned and proposed future generation plants (MEUG NZIER)

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4 We also note that the LRMC is an optional parameter that could be introduced by Transpower if it promotes the efficient use of Transpower's grid assets that are not connection assets, so as to efficiently defer investment, with the proviso being that it must complement or augment, but not duplicate, the price signals provided by nodal pricing and other charges under the TPM. To our mind, this underlying linkage between LRMC and the AoB price signal, and the desire to not duplicate, further supports the reasonableness of using LRMC as a proxy for the cost of the specific assets that will be charged for under the AoB proposal in the CBA.

- the current TPM is not currently driving large-scale investments in diesel distributed generation (PwC)… total 'liquid fuel' distributed generation capacity has declined from 105MW in September 2013 (which is the start of the data series) to 99MW in June 2016;

- The increase in capacity used in the CBA seems to be high compared to recent experience and also Transpower forecasts, (however some of this may be explained by differences in start dates) (MEUG NZIER);
- Benefits of RCPD assume that diesel facilities are used to avoid peaks at present whereas there are lower cost renewable options. (Genesis, Castalia);
- OGW assumes there would be a 40-fold increase in embedded diesel generation (from 12MW to 500MW) from parties seeking to avoid RCPD charges (EA Networks);
- Modelling neglects to account for the fact that the plants would have to operate for many more than 100 half-hour periods in order to 'hit' the 100 regional peaks and receive avoided cost of transmission payments – correcting this error would render much of that diesel plant unprofitable and reduce (if not wipe out) the $90m estimated benefit (EA Networks);
- The benefits that are said to arise from more efficient use of historical assets are assumed to arise primarily through avoiding an explosion in embedded diesel generation from customers seeking to avoid RCPD charges if the status quo remains in place (Transpower, Axiom);
- Used an assumption of all future DG being diesel powered which suggests they have not been adequately informed by the EA on the consented DG site in its energy database? (NZ Energy);
- Calculations assume construction and operation of new diesel distributed generation facilities will take place if the cost of these facilities, in $/MWh, is lower than the current RCPD charge of $2,132/MWh, calculated from 100 half hour RCPD periods… OGW have assumed that the new diesel distributed generation facilities would operate for 200 half hour periods to ensure that all 100 half hour RCPD periods are met. However, OGW have neglected to account for the fact that RCPD charge revenue can only be obtained during the 100 half hour …This error is confirmed in Footnote 95 of the DGPP paper…(the incentive is $1,100/MWh). (Pioneer);
  - Cost of new diesel DG at $550/kW is unrealistically low compared to NZ market experience...MBIE publish NZ data (Pioneer) in EA marginal cost calculator – it is $1,200/kW…MBIE estimates between $1,913 and $2,524/kW.
  - Correcting the above errors in the CBA would reduce the RCPD Charge Benefit that has been determined by OGW by $134m, from $90m to -$44m (Pioneer); and
- The CBA's estimate for the cost of installing new diesel generation is inaccurate.
  "[
  ]" The true cost is likely to be around $"[ ]" per kW, not $550 per kW as estimated by the Authority. (Trustpower)
- Deferrals of transmission investment: if using mobile diesel generators truly is a cost effective means of deferring capex we would assume Transpower would do this anyway…It is not clear why this is a benefit that will be delivered only by the proposed new TPM (if the new TPM increases the probability of this outcome, then the NPV value should be multiplied by that probability (PwC)

5.2. Response to issues regarding the diesel generation assumptions

There appear to be three key themes underpinning the comments:

- **The diesel generation cost is too low:** Regarding the cost of diesel generation, our assumption has been that the units installed would be of a small scale (e.g., 1-2MW), self-contained (containerised) and standardised units – noting that units of this size are more likely to be able to use existing connection assets to inject back into the distribution network (i.e., they can possibly be co-located with an existing load). Such units also have relatively simplified injection processes with in-built standard features (e.g., 'loss of mains' protection relay and grid synchronisation) and self-contained 8hr fuel tanks with multiple injection points into a distribution grid. From a purely commercial perspective, such units also have the added benefit of being more flexible (in terms of their location), yet they still have reasonably long lifespans (e.g., 20,000 hours). In short, they are likely to be a reasonably suitable technical response to the price signals being analysed. Some of the cost figures referred to by respondents are more consistent with permanent, larger scale diesel generation units, which would require different installation and integrity requirements (e.g., connection and network augmentation, additional fuel storage). Whilst this may be a solution that is adopted in some cases it is not the solution that we believe should be modelled in the context of the price signals being analysed.

  Based on information provided by Trustpower directly to the Authority, they estimate that the cost of a '[ ]' is currently around “[ ]” ($NZ). In deriving this figure[5], it appears that Trustpower has “[ ]” to get a per MW figure. However, it is our understanding that the peak rating of this machine is “[ ]”, and the continuous rating of the machine is “[ ]”. If this is correct, it is not clear to us why the total cost “[ ]”. If this is the case, this adjustment would reduce Trustpower's calculated figure in the order of 10%, to “[ ]”. A continuous rating would be more applicable for lengthy periods of operation.

  However, a review of publicly available information indicates the cost of the same model “[ ]” varies significantly, with most quoted prices being significantly lower than the price quoted by Trustpower - see Table 1.

Table 1: “[

]”

“[ ]”, all except one of the generators available would cost less than “[ ]”, with most being around “[ ]”. Furthermore, despite having been used for a reasonable number of hours, with an average life of around 20,000 hours, they all are likely to have the ability to meet the small levels of utilisation required to respond to the RCPD price signal for the assumed modelled life (20 years).

Trustpower has indicated that they are “convinced” that we have under-estimated the overall costs “[ ]”. Based on the information provided to us by the Authority, it is not clear how much Trustpower assumes each of these costs contributes to the overall pool of additional costs that would need to be incurred. However, Trustpower estimate that in total, these costs would bring the total cost to around “[ ]” (based on Trustpower's capital cost of '[ ]”, implying the additional costs would add around “[ ]”.

5 “[ ]”

Therefore, we are unable to reconcile the differences in costs and remain of the view that costs assumed in our modelling for the type of facilities we have assumed are reasonable. We also note that if the implied level of additional costs Trustpower submits we omitted were added to the capital costs in Table 1 '[ ]", the overall cost is very similar to the NZ$550/KW we used for modelling purposes. We reach this conclusion before considering sensitivities in relation to WACC and market revenue discussed below (just prior to Table 2).

- **There was an error in our calculation:** Upon reviewing our modelling, we agree with the observations made by Pioneer that we neglected to account for the fact that payments for operation during RCPD periods can only be obtained during the 100 half hourly periods, not the 100 hours of operation. We thank Pioneer for bringing this to our attention. Pioneer notes the error does not have a material effect on the CBA but also makes a similar point to Trustpower in relation to the cost of diesel plant which we have addressed in the previous point: "*The above error in itself does not change the level of benefit OGW have determined as the LRMC of new diesel distributed generation, $132,000/MW or $1,125/MWh over 200 half hours, calculated by OGW is marginally (3%) lower than the revised RCPD charge of $1,156/MWh…. However, OGW's estimate of the cost of new diesel distributed generation is considered to be unrealistically low when compared to New Zealand market experience and publicly available information. Specifically, the construction cost of $550/kW is considered to be below any reasonable lower bound for this type of application, and is thought to include plant purchase costs only and exclude wider project costs associated with resource consent, storage, electrical connection and transmission infrastructure, transport and civil work*".

  As noted by Pioneer, if a total cost of $550/KW is assumed, the above error in itself does not change the level of benefit we have determined, as the cost is still lower than the RCPD charge.

  Notwithstanding this, clearly a business' actual net costs and benefits will be heavily driven by its assessment of:

  - their own WACC, as compared to the WACC we are required to use for this analysis;
  - whether they are able to use an existing network connection or not, or whether they are subject to significant costs associated with resource consent etc;
  - the exchange rate;
  - the life of the generator;
  - whether the proponent is able to monetise any other benefits stemming from the operation of the plant that would further support its business case (e.g., offset retail or wholesale charges); and
  - views regarding how the RCPD charge may move in the future (i.e., will it increase or decrease).

For example, if the WACC were 5%, which based on information from the Authority, may be more likely to be reflective of current conditions in NZ than the 8% WACC we were required to use to undertake the CBA analysis, the cost is $2,010/MWh as compared to the RCPD threshold we used in our modelling of $2312/MWh (in $2014/15)[6]. Looking at this another way, this would mean that the breakeven price of investing in a diesel generator is $740/KW. However, this assumes an RCPD price signal denominated in $2014/15. After accounting for three years' of inflation (assume 2.5% per annum), the RCPD charge increases to $2490/MWh, and the breakeven point becomes $850/KW. If the plant were able to monetise the benefits it provides to the wholesale market over its 100 hours of operation, this would lead to a breakeven point of around $910/KW[7]. If the plant were to last for 25 years[8], instead of the assumed 20 years, this would further increase the breakeven point to $960/KW (excluding any wholesale price benefits) or $1030/KW (inclusive of any wholesale price benefits).

At a slightly higher WACC of 6%, the breakeven becomes around $780/KW with an RCPD charge of $2490/MWh, without any wholesale market benefits, and around $840/KW if wholesale market benefits are included. If the plant lasts for 25 years, and not 20, these figures change to $870/KW and $930/KW respectively.

Further, if the WACC was much higher at say 10%, the breakeven is around $580/KW, without any wholesale market benefits, and around $625/KW with wholesale market benefits.

If the WACC were to remain the same as originally modelled, but instead we assumed that the RCPD charge did increase for three years' of inflation and that the diesel generator could monetise the wholesale price benefits it provided, and the generator would last 25 years, then the breakeven would be around $780/KW.

Overall, whilst none of this provides a definitive answer one way or the other, it clearly shows how sensitive the results are to the input assumptions, particularly the WACC and the future RCPD price, and, as has been discussed previously, the upfront cost of the generator itself.

Clearly, financing conditions are particularly favourable at present, which benefits investments with high upfront costs and a long stream of cash inflows. Regarding the RCPD, it is clear that this rate has increased significantly over the last 10 years.

Table 2: RCPD rate

Component	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Total Interconnection Revenue ($/m)	411.50	413.61	447.06	546.98	574.15	661.11	632.19	662.09	715.16
Interconnection rate ($/KW)	70.94	69.12	76.14	90.66	99.44	114.47	110.35	114.64	123.98

6 https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPM-Attachment-B%20background-supporting-analysis.pdf

7 Based on 100 hours at $50/MWh.

8 As noted earlier, the average life of stand-by diesel generators is around 20,000 hours. Given the very small assumed use per annum (100 hours), 25 years is definitely a feasible lifespan for this type of product.

Source: Transpower, "Transmission Pricing Data for 2017/18 Pricing Year"

For completeness, the rate has increased by 8.3% in nominal terms since 2014/15, which, absent small changes in the Total Regional Coincident Peak Demand (MW), would bring the original $/MWh figure published by Transpower of $2312 to $2504/MWh, which is consistent with the inflation adjusted figures we have used above ($2490/MWh). In a 2014 document[9], Transpower provided forecasts of its interconnection rate. This indicated that it was expecting small nominal increases in the rate for 2018/19 and 2019/20. Another publicly available piece of information indicates that Transpower expects similar revenue from interconnection charges in 2024/25 (the latest year forecast, which is in RCP3) as its revenue path for RCP2[10].

In conclusion, having regard to all of this information, including the publicly available information on purchase prices for second-hand generators, we remain of the view that our original analysis of the potential costs of the type of plant we have specified are reasonable. Therefore, even after allowing for the original calculation error in respect of hours over which revenue is generated, the information available does not dissuade us from our original position that it is likely to be economic to build a diesel generator (to the specification we have discussed earlier) in the future.

For completeness, it is noted that if we were to assume no diesel generation was built in response to the RCPD charge in the future, the CBA would still have net benefits.

- **The magnitude of the take-up, as compared to historical figures**: For example, one respondent has stated that total 'liquid fuel' distributed generation capacity has" *declined from 105MW in September 2013 (which is the start of the data series) to 99MW in June 2016*", whilst another has stated that "*OGW assumes there would be a 40-fold increase in embedded diesel generation (from 12MW to 500MW) from parties seeking to avoid RCPD charges*". Whilst it is not immediately obvious from reading the comments, which of the figures provided by the respondents is correct (12MW or 99MW), at the time of completing the CBA, it was our understanding that there was around 100MW of this type of generation in NZ, which indicates a very different, and much more reasonable, increase of 4-fold over the 20-year time horizon. Moreover, whilst the historic take-up is of interest, it reflects factors affecting take-up during that particular period, which may not hold into the future. For example, the price of diesel has come down over recent years, whilst the RPCD price signal has gone up significantly since 2008, both of which are likely to change the economics of making such investments.

Our responses to the other matters that have been identified are as follows:

9 Transpower, *2015/16 to 2019/20 Transmission Revenue*, July 2014 [https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/RCP2%20revenue%20-%20revised%20forecast%20(July%202014).pdf]

10 https://www.transpower.co.nz/industry/revenue-and-pricing/revenue

- **Modelling neglects to account for the fact that the plants would have to operate for many more than 100 half-hour periods in order to 'hit' the 100 regional peaks and receive avoided cost of transmission payments - correcting this error would render much of that diesel plant unprofitable and reduce (if not wipe out) the $90m estimated benefit (EA Networks):** On face value, the statement that "*they would have to operate for **more** than 100 half-hourly periods **[emphasis added]***" is already accounted for as we have reflected the costs of running for 100 hours (i.e., double the amount of hours that the RCPD price signal applies to).
- **The benefits that are said to arise from more efficient use of historical assets are assumed to arise primarily through avoiding an explosion in embedded diesel generation from customers seeking to avoid RCPD charges if the status quo remains in place (Transpower, Axiom):** The more efficient use of historical assets are assumed to arise primarily through avoiding an increase inefficient diesel generation, but as is discussed below, this does not mean that other efficient forms of DG will not also be constructed..
- **Used an assumption of all future DG being diesel powered which suggests they have not been adequately informed by the EA on the consented DG site in its energy database? (NZ Energy):** We have not been informed by the EA of any "*consented DG site in its energy database*", therefore, we are unable to comment as to whether this is of relevance or not. In relation to the assumption that "all future DG is diesel", as we have previously discussed (e.g., at the Wellington workshop), this assumption does not necessarily mean that other forms of DG will not be built in the future. Rather, implicit within this assumption is that other low cost (i.e., efficient) alternatives to transmission investment would still be built in the future, it is just that it would be built in response to the AoB price signal (as it relates to future augmentation expenditure) as opposed to the RCPD price signal. Therefore, changing this assumption would make no difference to the results, hence why our modelling, which looks at the incremental differences between the proposed charging arrangements and the status quo, focuses on whether any *inefficient* DG such as diesel generation might be built in response to the RCPD price signal.

6. The LRMC calculations do not match the input assumptions and this significantly affects the proposal's net benefits

6.1. Summary of the issues raised regarding the assumption that the proposal is efficient

The Authority has asked us to consider a number of issues raised by respondents around the LRMC calculations not matching the input assumptions. The comments that were provided by the Authority that we have had regard for include:

- OGW adjusted raw LRMC calculations downward by 30% and 40% - these adjustments are the two biggest sensitivities in the CBA…an arbitrary figure used by OGW to make LRMCs consistent with Australia. The resulting LRMCs don't reflect NZ. (Pioneer CBA document) There is strong evidence that the LRMCs should be higher …higher load LRMCs would reduce net benefits to a minimum of $67m…revising the 40% discount to 0% would reduce net benefits by $586m….The cumulative effect of this is that the CBA assumes over 90% of all transmission expenditure will not be effectively signalled to the end user (Pioneer CBA document); and

- OGW analysis suggests that the new pricing arrangements will signal to the end customer only 3% of the total annual Transpower expenditure (Pioneer)… the Proposal does not provide an effective price signal to influence change in customer behaviour in response to that price signal (Pioneer)

6.2. Response to issues regarding the assumption that the proposal is efficient

The general themes appear to be related to the:

- Adjustments that we made to the raw numbers provided by the Authority to generate an LRMC estimate; and
- Relatively small portion of capex that is assumed to be an effective signal to end customers.

In relation to the first issue, we feel we were very transparent in our report with regards to:

- The fact that we made these adjustments;
- Why we made these adjustments; and
- How we made these adjustments[11].

That said, Pioneer is correct in stating that we had regard for LRMCs in other jurisdictions when making adjustments to the raw numbers provided by the Authority to generate an LRMC estimate. Firstly, the reasons for making adjustments in the first place were explained in the report. Secondly, the reason why we referred to other jurisdictions was because we were unable to identify any robust published data that related to the NZ market during our literature review.

Our original report (footnote 33) makes reference to the information from the Australian Energy Market Operator (AEMO) that we primarily relied upon, so we will not repeat that here. However, we also had regard for other published estimates from Australian distribution businesses, particularly for their sub transmission network (which is obviously the distribution voltage that is most likely related to the transmission). For completeness, these are provided below.

Table 3: LRMC estimates for sub transmission by a selection of Australian distribution businesses

Business	Values
Endeavour Energy	Endeavour Energy, Tariff Structure Statement, page 69: Sub transmission - $17 / kVA / annum
Ausgrid	Upper range of LRMCs outlined in Ausgrid's Tariff Structure Statement (page 45) Sub transmission - $8 / kVA / annum
Essential Energy	Aggregated estimates of the LRMC by voltage level are outlined in Essential Energy's Tariff Structure Statement (page 58). Sub transmission - $32 / kVA / annum
SA Power Networks	Aggregated estimates of the LRMC by business category are outlined in SAPN's Tariff Structure Statement (page 10 of Appendix B). Major business (assumed to equate to sub transmission) - $35 / kVA /

11 In particular, please see Appendix A of our original report.

	annum
Powercor	Estimates of Powercor's LRMC by voltage level (and business category) are outlined in Powercor's Tariff Structure Statement (page 52) Sub-transmission - $9.8 / kVA / annum
Energex	Estimates of Energex's LRMC by voltage level are outlined in Energex's Tariff Structure Statement (page 32). Sub-transmission - $5.032 / kVA / month

Source: Various Tariff Structure Statements published over the last 12 months.

As can be seen, almost all of these LRMC estimates range between $5/kVA to $35/kVA per annum, which is consistent with the figures that we utilised in the CBA. Furthermore, these LRMCs have been:

- Calculated by different people (because there are multiple businesses); and
- Cover various types of topography's and customer densities, from AusGrid and Energex (central Sydney and Brisbane respectively, plus surrounding urban and semi-urban areas) to Endeavour (urban, semi-urban and mountainous semi-rural areas in parts) to Powercor and Essential (predominately rural),

hence providing further support to it being a reasonable range.

We note that the respondent's submission does not provide any new evidence to suggest why there is a material difference between the cost in NZ versus Australia, nor the magnitude of any cost difference. Moreover, it is our understanding that Transpower, who presumably would be best placed to comment on this issue, did not raise the overall magnitude of the LRMC as an issue.

Finally, we note how the LRMC estimate effects the calculation of benefits in the CBA. In particular, the higher the LRMC is, the:

- Lower the economic cost of retaining the RCPD is, *however*
- Greater the economic benefit of applying the AoB charge to new investments is.

This is not to suggest by any means that these counteract each other, but rather, simply to highlight that it is less about the LRMC value per se, and more about the fact that the:

- RCPD does not align with the LRMC (for example, Transpower itself states that the "*RCPD charge is not well correlated to LRMC*[12]"); and
- Cost of new augmentations are not signalled directly to the beneficiaries of those assets, who in turn are the parties who could possibly change their consumption or investment behaviour in response to that price signal.

12 Transpower, *Transmission Pricing Methodology, 2nd Issues and Proposals Paper*, 26 July 2016, page 6

In relation to the second issue, the CBA indicates that the proposed TPM, which includes amongst other things the application of the AoB approach to signalling the cost of future transmission investments, will lead to positive net benefits. Whether or not it will "*signal to the end customer only 3% of the total annual Transpower expenditure*", as one respondent states, or that "*over 90% of all transmission expenditure will not be effectively signalled to the end user*", as that respondent states elsewhere in their submission, is we believe not relevant, in and of itself. Rather, it is the magnitude of the benefits compared to the costs of a different TPM that determines if the different TPM has net positive impact. Intuitively, much of Transpower's expenditure will occur regardless of the way in which its costs are recovered and it is therefore not surprising that the TPM will affect only a small percentage of the total. The introduction to our methodology noted that the CBA was based on costs that would change as a result of a different TPM. Moreover, the percentages quoted do not reflect the impact of changing how the costs of historical investments are recovered (e.g., the RCPD charge), which also impacts on the CBA results.

7. The assumption that generators are built based on LRMC is inaccurate

7.1. Summary of the issues raised regarding the assumption that generators are built based on LRMC

The Authority has asked us to consider a number of issues raised by respondents that generators are not built based on LRMC. The comments that were provided by the Authority that we have had regard for include:

- The CBA equates each generator's average total cost with system-wide LRMC. This does not represent the way new entry decisions are made in practice. For example, the approach assumes it will always be more efficient to build a peaking unit. (Axiom for Transpower), and
- Oakley Greenwood's framework assumes that generators would be built based on long-run marginal cost. This is not accurate as a $/MWh basis, which should be used. In practice, it is a balance of energy and capacity costs that are likely to determine the order of generation. (HoustonKemp for Trustpower)

7.2. Response to issues regarding the assumption that generators are built based on LRMC

At a general level, we accept that the approach we have adopted to model the potential benefits of being able to co-optimise transmission and generation costs is a simplified version of reality. That is, it will not be just growth in peak demand that triggers investment, nor will the order be purely based on the $/MWh estimate of the LRMC. However, a CBA assesses whether there is likely to be net benefit of a proposal. Modelling of complex decisions by multiple parties facing uncertainty over an extended period can only ever be an approximation.

The key question we confronted was what is a reasonable approximation to the decisions that will affect costs. In respect of the use of LRMC, the critical issue was whether there would be a material change in the amount of generation built, and more importantly, whether there would be a re-ordering of generation and transmission as a result of the application of the TPM proposal. We concluded that analysis based on LRMC was a 'fit for purpose' approach to answering these questions. Further we note that if the amount and order of investment is inconsistent with LRMC it would indicate a much deeper problem. Finally, we note that no evidence has been presented to suggest that LRMC based analysis would be biased one way or another.

8. There were issues with the "more efficient co-investment between generation and transmission" benefit

8.1. Summary of the issues raised regarding the "more efficient co-investment between generation and transmission" benefit

Following on from the above section, the Authority has asked us to consider a number of other issues raised by respondents relating to how we have modelled the more efficient co-investment between generation and transmission benefit. The comments that were provided by the Authority that we have had regard for include:

- Assumptions for generation benefit:
  - material amount of generation required over the next 20 years
  - Grid expansion is required
  - Costs to expand grid differ materially across regions
  - Costs to build different types of generation need to be similar (ENA)
- Assumes the 'shadow price' signals provided by the AoB charge would be 'efficient' (EA Networks)
  - it is assumed that each generator located in, say, the LNI would face the same AoB charge under the proposed methodology – and that the charge would equal the regional LRMC of transmission (EA Networks)
  - By assuming at the outset that the AoB charges would be perfectly efficient the CBA must, by definition, conclude that future generation and transmission costs would be lower if the proposal was implemented (EA Networks)… This is not an appropriate way to undertake a CBA
- There is no modelling of dispatch to determine which plants will be built and when (EA Networks)
- The model assumes that new generation investments will be made on the basis of the average total cost (ATC) of a unit of generation (which the CBA mischaracterises as the LRMC of generation) (EA Networks)
- The model erroneously assumes that a generator's impact on the LRMC of transmission depends upon how many hours a year it runs (EA Networks)
- Huntly stays/Huntly goes: Equal weighting for more efficient generation benefit…but Huntly stays indefinitely for other benefits…It is more likely that Huntly goes as its expected to close in 2022 (Pioneer)

- LRMCs of transmission will be significantly higher in the event that Huntly goes. Revising the Load and Generation LRMCs to reflect the scenario in which Huntly goes in the CBA would reduce the total net benefits by $169m, from $213m to $44m. (Pioneer)
- Uses generation LRMCs and the MBIE model…OGW assumed that co investment in generation and transmission is perfectly efficient. However there is significant uncertainty as it considers 4% of the total annual transmission expenditure will ultimately be reflected in transmission price signals…also ignores that transmission investment is subject to economic sizing effects and generation investment is primarily influenced by a myriad of other factors. (Pioneer)
- Assumptions – capex – changing the generation/load capex split from 40% to 20% would mean the most material change in the generation schedule would not occur. (p.12)…also the Authority only allocated 21% of historic transmission investment to generation. (Pioneer,)
- MBIE model out of date (Pioneer)..removing abandoned projects would reduce benefits
- OGW ignored the impact of the wholesale market on providing a material transmission pricing signal for generation and OGW does not enable net benefits to be less than zero. (Pioneer)
- It is inherent to this analysis that DG is more efficient that grid connected- this contrasts with the general conclusion of the paper. (Pioneer)
- The use of modelling techniques to estimate the path of efficient generation entry which are not fit for this purpose
- The absence of terminal values or other techniques that might mitigate the influence of upfront capital costs in its cash flow analysis, which is subject to substantial risk of error
- The absence of various cost categories, including fuel costs, in its cash flow analysis, which means that it does not assess the full cost of generation entry in its comparison
- The failure to take into account the potential for some technologies, such as wind, not to be reliably able to contribute their rated capacities at peak times
- The lack of information demonstrating the basis for the calculation of benefits from the removal of the HVDC charge
- The selection of a probability associated with Huntly shutting down of 50 per cent
- The assumed immediate timing of a Huntly shutdown in the scenario in which it eventuates
- The inconsistency of its results with those produced by its predecessor agency in 2010, based on a very similar modelling framework. (Pioneer)

8.2. Response to issues raised regarding the "more efficient co-investment between generation and transmission" benefit

The comments are many and varied, however, the general themes appear to be:

- The model presents a simplified picture of the real world (e.g., assumes the 'shadow price' signals provided by the AoB charge would be 'efficient'; the absence of detailed dispatch modelling; the model assumes that new generation investments will be made on the basis of the average total cost (ATC) of a unit of generation):

- As discussed in the previous section, the CBA is intended to reflect future decisions, not to model detailed decision processes that would be undertaken on a project by project basis with contemporary information about costs and specific locations. That is to say, the model presents a simplified picture of the real world so as to estimate the benefits of the proposal it is modelling. For example, the CBA analysis does not reflect a bespoke analysis of the exact transmission costs that would need to be incurred to connect each potential new generator, rather, an estimate of the LRMC by region has been used to estimate this. The key question to our mind was: can transmission costs vary from one generator to the next, and in the absence of detailed, bespoke modelling (which itself would be more precisely modelling significant uncertainty), is an estimate of the LRMC within particular regions within NZ a reasonable way of measuring this difference? We answered these questions: yes and yes. Note we are not suggesting that in the real world that the actual transmission cost that will be incurred by a generator will perfectly reflect the LRMC that we have used for modelling purposes – rather they will almost certainly be higher or lower.
- Regarding the use of dispatch modelling, again, the respondent is correct in stating that we did not utilise a detailed dispatch model to determine the future generation schedules and therefore augmentation requirements, rather, we adopted a much simpler approach, and one that was much more transparent. Will the dispatch order in our model (both with and without the TPM) reflect exactly what will happen in the future – almost certainly no. However, we consider it is an unbiased estimate of what level of new generation might be required in the future under both the with and without the new TPM scenarios. It is based on publicly available information regarding the capital costs of new generation sources, their variable and fixed operating costs, their name plate capacity and their expected outputs (which collectively allow us to derive the total cost of that generator), and an estimate of the LRMC of transmission.

- Assumptions (e.g., use of MBIE model is out of date; changing the generation/load capex split from 40% to 20%; selection of a probability associated with Huntly shutting down of 50 per cent; failure to account for some technologies, such as wind, not to be reliably able to contribute their rated capacities at peak times; is inherent to this analysis that DG is more efficient than grid connected - this contrasts with the general conclusion of the paper) – Regarding some of the key assumptions that were questioned, we note that:
  - We used what we understood to be the most up-to-date, published information regarding future generation options in NZ. The Authority was aware that we were relying on the MBIE data, and to this end, did not raise any concerns or issues relating to this data source;
  - The generation/load capex split was provided by the Authority;
  - The probability of Huntly shutting down was provided by the Authority; and
  - It is correct that we did not discount the capacity of wind to reflect its reliability to contribute their rated capacities at peak times. This was an oversight on our part, given the broader methodology that we proposed. That said, the assumption about the wind farm's capacity affects both states within the modelled time frame of 20 years (i.e., if we had de-rated the wind farms, then the model would build a different number of generators but exactly the same amount of additional peak capacity under both the proposal and the status quo cases), hence diminishing its effects in the overall result.

  - It is not clear to us why it is "*inherent to this analysis that DG is more efficient than grid connected*". It is not an assumption that we made consciously and do not see that it is implied in the calculations, therefore, we are not in a position to respond to this comment.
- Absence of certain costs (e.g., absence of terminal values; the absence of various cost categories, including fuel costs);
  - Terminal values were not included, however, under both the base case and TPM proposal case, we assumed that exactly the same amount of capacity is built, hence limiting the impact of this issue;
  - It is unclear to us why the respondent assumes that there is an "*absence of various cost categories, including fuel costs*". The MBIE data includes the cost categories one would expect it to include for each candidate generator, namely: capital costs, fixed operating costs and variable operating costs, which includes fuel costs;
- Inconsistency of its results with those produced by its predecessor agency in 2010, based on a very similar modelling framework;
  - We are not in a position to comment on this, as we were not involved in any of the work undertaken in 2010;
- The lack of information demonstrating the basis for the calculation of benefits from the removal of the HVDC charge;
  - This was explained in section 8.4 (page 49) of the original report. We have been informed by the Authority that this modelling was published.

9. The assumptions are not realistic or are in error

9.1. Summary of issues raised regarding assumptions not being realistic or being in error

The Authority has asked us to consider a number of issues raised by respondents that some of the assumptions are not realistic or are in error. The comments that were provided by the Authority that we have had regard for include:

- Proposal is nodal – CBA is regional (PwC);
- CBA represents capacity to satisfy maximum demand…does not represent half hourly dispatch or variation in demand…simplification by providing a single LRMC of a specific project. The model equates to each generators average total cost (ATC) with the concept of a system wide LRMC – these concepts aren't substitutes for one another (Transpower, Axiom) ATC is a poor predictor of whether that unit is the cheapest way to meet an incremental demand.
- Modelling has not taken account of constraints associated with hydro. (Transpower, Axiom);
- No adjustment has been made to account for the intermittency of wind generation (Transpower, Axiom);
- The calculation of benefits assumes that each plant generates according to its assumed capacity factor (Transpower, Axiom);
- Assumed that changes to the TPM perfectly flow through to end users as cost-reflective retail prices;

- 2% increase in electricity consumption for its modelled life-time benefits which has not been achieved regionally or nationally in recent history (Vector);
- Opaque inputs provided by the Authority regarding regional demand growth rates (PwC);
- OGW incorrectly allocated peak demand between USI and LSI regions…also Transpower estimate for the national peak demand does not equal the sum of regional peaks. Correction – reduces benefit from 90m to 82m. (Pioneer);
- Assumes no low cost alternatives to transmission investment (hydro, geothermal, solar) is a gross oversimplification. (Pioneer)… – there is 200MW of consented low cost DG in the public domain. (Pioneer) …if low cost DG were acknowledged it would have a significant impact on the proposal...revising cost of new DG to $32,632 would reduce the RCPD benefit from $90m to -48m.
- The CBA estimates cost and capabilities of demand response based on Transpower's demand response trial. This is inadequate as it was a pilot, experimental programme (Trustpower)
- Concerned that the modelling does not seem to question whether the benefits assumed from post-2004 transmission investments are tangible (Energy Trust of NZ)… appropriate to treat a significant proportion of the capex involved as an imprudent investment; and
- RCPD values used in the model do not reflect Transpower RCPD (Orion)

9.2. Response to the issues raised that the assumptions are not realistic or are in error

Firstly, how we modelled generation benefits has been discussed in sections 7 and 8, hence readers should refer to this material for more information.

In addition to the comments on our generation modelling, there are two statements that relate directly to information that the Authority provided us with to undertake our modelling ("*2% increase in electricity consumption*" and *"Opaque inputs provided by the Authority"*), which the Authority is best placed to respond to (although in relation to the former, we understand that the Authority has sourced the increase in electricity consumption from Transpower).

Regarding a number of the other key assumptions, our responses are:

- **Proposal is nodal – CBA is regional:** Yes, this is correct. As we have stated previously, the CBA is intended to reflect future outcomes not to represent or forecast in detail. That is to say, the model presents a simplified picture of the real world so as to estimate the benefits of the proposal it is modelling. Implicitly, a regional analysis of a nodal arrangement means the it is based on the average of nodal outcomes. For the purposes of a CBA over decades such an approximation is not unreasonable in our view. Further, we did not have access to nodal information (e.g., capital expenditure forecasts at a nodal level over the entirety of the evaluation) in any event. Finally, we do not think that this treatment systemically biases the results upwards.

- **Assumes no low cost alternatives to transmission investment (hydro, geothermal, solar) is a gross oversimplification:** As we have previously discussed (e.g., at the Wellington workshop), the "simplification" is that any low cost (i.e., efficient) alternative to transmission investment would still be built in the future, it is just that it would be built in response to the AoB price signal (as it relates to future augmentation expenditure) as opposed to the RCPD price signal. Put another way, changing this assumption would make no difference to the results, because if there were additional low cost alternatives available in the future (i.e., lower than the cost of the alternative investment, being a transmission investment), these solutions would be built under both the RCPD charge and the new AoB charge. This is because the AoB price signal (as it relates to future augmentation costs) would signal the costs of future investments on an asset specific level, and if DG (or any other alternative) was a more efficient solution, then the party having to bear the AoB charge for that asset would be incentivised to procure that more efficient DG (or any other alternative).
- **OGW incorrectly allocated peak demand between USI and LSI regions**: We can't comment on the veracity of this comment. If the Authority confirms the statement, then we can make any necessary adjustments to the modelling.
- **The CBA estimates cost and capabilities of demand response based on Transpower's demand response trial:** Yes, this is correct. Whilst the actual cost of DR is likely to vary relative to these results, to our mind, the probability of outturn results being materially higher is likely to be similar to them being materially lower, particularly over the quantum of DR we assumed could be incentivised over the evaluation period at this cost. More generally, it is unclear why this empirical information is not considered to be a reasonable means of generating an input assumption such as this, given the broader absence of information on this issue.
- **Concerned that the modelling does not seem to question whether the benefits assumed from post-2004 transmission investments are tangible:** It is correct that we did not make any explicit assumption regarding whether or not the benefits that are assumed from post-2004 transmission investments are tangible. However, as we discuss in section 15 of this report, subject to two provisos, the way in which historical investments are recovered should not materially influence economic efficiency of future charges, as these costs have already been incurred, and therefore, cannot be reversed and therefore would be common to the counterfactual and proposed TPM. The two provisos are that the recovery mechanism minimises the extent to which the recovery of those costs:
  - Distorts the future usage of the existing network (e.g., consumption decisions); and
  - Leads customers (including generators and distributed generators) to make inefficient connection, disconnection or other investment decisions.

  In this context, it is not clear from the respondents comment if the threshold tests have been met, and if so, whether it believes these thresholds might be breached as a result of this issue.
- **RCPD values used in the model do not reflect Transpower RCPD**: This was a labelling error, and the 'RCPD numbers' referred to actually represent regional (winter) peak demand numbers provided by the EA to OGW on 7 December 2015 (Transpower National-Regional Peak Demand Forecasts Feb2015.xlsx). The use of these numbers, which we understand the Authority sourced from Transpower, impacts on the calculation of three impacts within the CBA:
  - Benefits of removing the RCPD charge;
  - Demand response (as a transmission substitute); and

- Reduced demand (through the elasticity impact).

Peak demand is assumed to be the underlying driver of the need to make investments to augment the transmission network, therefore we have linked the take up of DG (where economic) to peak demand figures – NOT the RCPD figures. We consider that this is reasonable. Similarly, the incentive for demand response (i.e. as a transmission substitute) is based on the cost of DR, relative to the cost of augmenting the transmission network. Again, given peak demand is assumed to be the underlying driver of the transmission augmentation, we have linked the take up of DR to the forecast of peak demand provided EA.

However, the reduced demand (or elasticity impact) should have been explicitly based on the RCPD numbers, however the impact of changing these numbers is immaterial (e.g. less than $200k impact).

10. There are no benefits from removing the RCPD charge

10.1. Summary of the issues raised regarding there being no benefits from removing the RCPD charge

The Authority has asked us to consider a number of issues raised by respondents that indicate that there is no benefit from removing the RCPD charge. The comments that were provided by the Authority that we have had regard for include:

- Deterring additional investment in and use of substitutes $90m benefit (Trustpower):
  - Assumes interconnection charge would trigger DG and DR investment;
  - RCPD and diesel prices incorrectly compared – unrealistic level of response;
  - Inconsistent in treatment of Huntly – left in for this analysis – although it will likely be out by 2022; and
  - Additional assumptions not referred anywhere.
- Attributes benefits to the AoB charge whereas they could be received under a range of options
- It is not plausible to suggest that around $850m (in NPV terms over twenty years) in additional transmission charges could be allocated to load customers without there being at least some reduction in demand (Transpower, Axiom)
- The cost-benefit analysis appears to have made a number of assumptions around retail prices and electricity usage at peak times, and would likely vary depending on which allocation methodology is selected by Transpower (Unison)
- CBA stated: “Presumably these higher (but more cost-reflective) transmission prices flow through to higher but more cost-reflective retail variable charges and as a result lead to lower peak demands during times when the network peaks, thus potentially reducing the cost of providing distribution services which would be an additional economic benefit” The above analysis does not make sense to Unison, particularly as the RCPD price signal in the current interconnection charge will be replaced by a more fixed and unavoidable residual charge based on capacity (Unison);

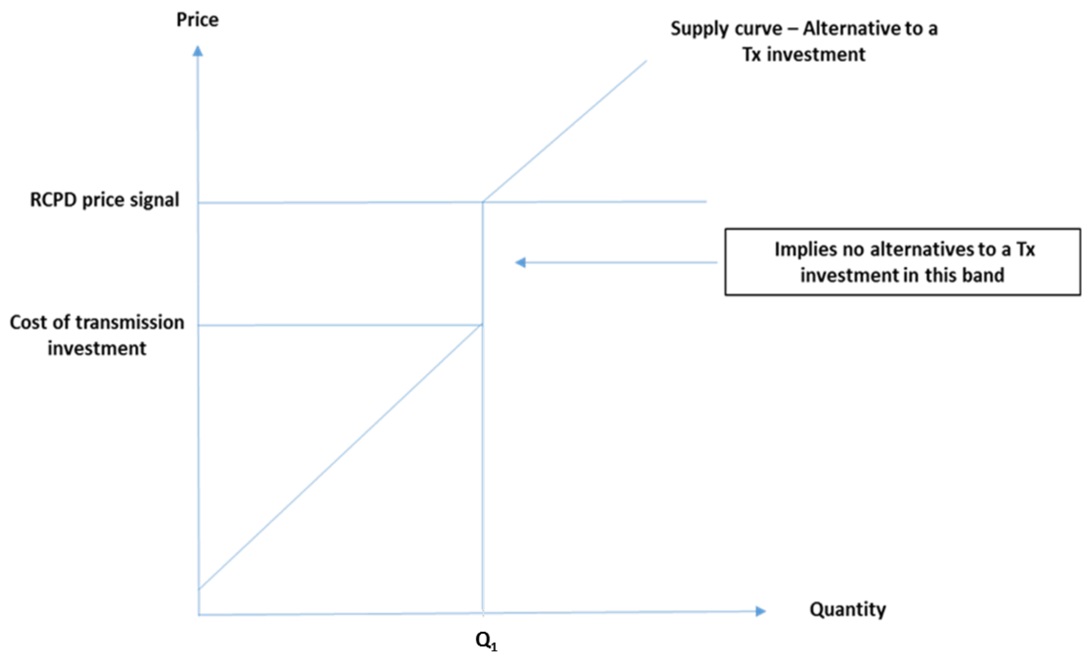
- Unison also questions how distributors and retailers will be expected to package these new Transmission charges into distribution and retail prices respectively? The assumptions around retail variable price increases ignore the context of future distribution pricing changes and speculate on customers' use of the grid (Unison)… If the AoB and residual charges become more difficult to avoid (e.g. based on capacity allocations as opposed to RCPD), fixed distribution and retail costs will likely increase not reduce, at least in the short-term. (Unison);
- Distributors will be incentivised to variabilise their charges benefit: Transmission investment requirements are driven by peak demand, not total variable usage. If distributors wanted to set prices to defer transmission investment they would set peak-based, not variable, prices (PwC)… The assessment within the CBA is in conflict with the Authority's position in relation to distribution pricing , which is supportive of less use of variable charges and increased use of capacity or demand-based charges (PwC)… It is unlikely that a complex charge such as the AoB charge would be fully and transparently passed through by retailers;
- The assumption that existing demand response will respond to the proposed AoB charge is fundamentally flawed as the AoB charge does not provide an effective price signal to influence change in customer behaviour (Pioneer)… Including the conservative assumption of 700 MW of existing Demand Response (at $19,600/MW) in the CBA would reduce the RCPD Charge Benefit by $103m, from $90m to -$13m (Pioneer);
- Assumes ACOT = $62m. However, it is $52m for 2015 pricing year. There was a reduction in 2015 but it wasn't considered. …reducing ACOT to $56m would reduce the benefit by $3m;
- the net costs from removing an effective peak demand signal are conservatively estimated to exceed $500m/y, or $5b in equivalent NPV terms (Pioneer);
- A "punitive" benefit from tariffing sunk assets to beneficiary parties – an unheard of economic benefit (Vector); and
- The bulk of this benefit is realised from the lower probability of (larger grid connected) customers disconnecting from the transmission grid under the proposed TPM because their new charges would be less than under the existing TPM. The difference in charges is counted as a "producers' surplus" benefit to the customer and can be supplemented with a PDP as required. It appears that it is a transfer to consumers with no net benefit. …there are many factors that currently persuade customers to use local rather than grid generation, the RCPD charge being but one. Classing the difference as producer surplus and therefore a quantifiable benefit is too simplistic. The difference is simply a cost that is recovered from other consumers who are currently not being charged, and the opposite effect (dis-benefits) may well be the outcome (ENA)

10.2. Response to the assertion that there are no benefits from removing the RCPD charge

Firstly, to our mind, any statement that indicates that there are no benefits from removing the RCPD charge must meet a number of threshold tests. The tests are:

- That the RCPD charge reflects, and will continue to reflect, a robust estimate of the forward-looking costs of providing transmission services (e.g. Transpower's marginal cost) at each transmission node. This is despite the fact that the RCPD charge is not in fact designed to signal the costs of Transpower's future transmission costs, rather, the RCPD charge is predominately a means by which Transpower recovers the costs of its historical investments[13]. Even absent any analysis, this is unlikely to hold true. Further the RCPD price signal is the same across NZ, yet the forward-looking cost of providing transmission services will almost certainly be different in different areas. We note that Transpower states that the "*RCPD charge is not well correlated to LRMC*"[14], or
- Even if the RCPD charge does not meet the first test (above), it does not drive inefficient future consumption or investment behaviour. For this to hold true, one would need to establish that every single possible investment (whether DG or DR or anything else) that is promoted by the RCPD charge is cheaper than the alternate transmission investment. For this to hold true, the supply curve for alternatives to a transmission investment must be vertical over the price range that covers the difference between the cost of the alternative transmission investment, and the RCPD price signal. This is illustrated in the figure below.

Figure 1: Shape of supply curve for alternative to a transmission investment at every transmission node that would be required for the RCPD signal to <u>not</u> be distortionary



Source: OGW

Intuitively it is inconceivable that the supply curve for alternatives to a transmission connection take this form, *at every single connection node* where transmission investments are required across NZ for the entirety of our evaluation period (20 years).

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13 For example, Transpower states that the "*key difficulty with the RCPD charge under the current Guidelines is that it has to allocate around 70% of the total costs of the grid through a peak price.*" Transpower, *Transmission Pricing Methodology, 2nd Issues and Proposals Paper*, 26 July 2016, page 15

14 Transpower, *Transmission Pricing Methodology, 2nd Issues and Proposals Paper*, 26 July 2016, page 6

Accordingly, we cannot support a position that there are "*no benefits from removal of the RCPD charge*".

Regarding some of the specific comments that relate to the RCPD charge, we make the following responses:

- **Attributes benefits to the AoB charge whereas they could be received under a range of options:** Quite possibly, but our task was to undertake a CBA of the two TPM options developed by the Authority. Our role did *not* extend to consideration of other options for TPM.
- **It is not plausible to suggest that around $850m (in NPV terms over twenty years) in additional transmission charges could be allocated to load customers without there being at least some reduction in demand**: Firstly, based on reading the source document, it is not clear how this figure has been derived. Notwithstanding that, if we take the $850 million on face value, to our mind, this would not seem to us to be a particularly large proportion of retail electricity bills over a 20-year period. Moreover, and most importantly, the comment appears to conflate the impacts of the wealth transfer ("$850m…in additional transmission charges could be allocated to load customers") with the impact that is created by adopting inefficient retail pricing structures to recover those increased costs. Put another way:
  - if retail prices are structured correctly (i.e., businesses set marginal prices to reflect marginal costs); and
  - they recover residual costs including the costs of historical transmission investments through fixed charges that are set at levels that avoid incentivising end retail customers to change their future investment behaviour (including by inefficiently by-passing the network), then

  this shouldn't lead to inefficient consumption or investment behaviour as has been asserted.

  Structuring retail prices so that marginal prices reflect marginal costs is not only consistent with economic theory but one would have thought reflects a commercially sensible approach because setting marginal prices equal to marginal costs mitigates a business' volumetric risk.

  In relation to the second point ('inefficiently disconnect from the grid'), in the context of distribution businesses, there are real commercial and economic incentives for them to recover transmission costs (including additional transmission costs resulting from the introduction of the AoB charge) in a way that results in overall price levels sitting between a customer's, or group of customers' stand-alone[15] and avoidable costs. Within this framework, if a distribution business was of the view that the way in which they were recovering any of the additional transmission charges (as compared to the status quo) made it economic for a customer or group of customers to disconnect from its network (e.g,. Figure 2 below), it would reduce the fixed charges for those customers. It would then increase the fixed charges for other customers/customer classes (e.g., Figure 3 below), mitigating that risk, without comprising economic efficiency. In short, it would adopt a form or Ramsey pricing.

15 In this context, standalone cost reflects the customer's opportunity cost of staying connected to the network.

Figure 2: Potential impact of a wealth transfer, if there is no response from a distribution business

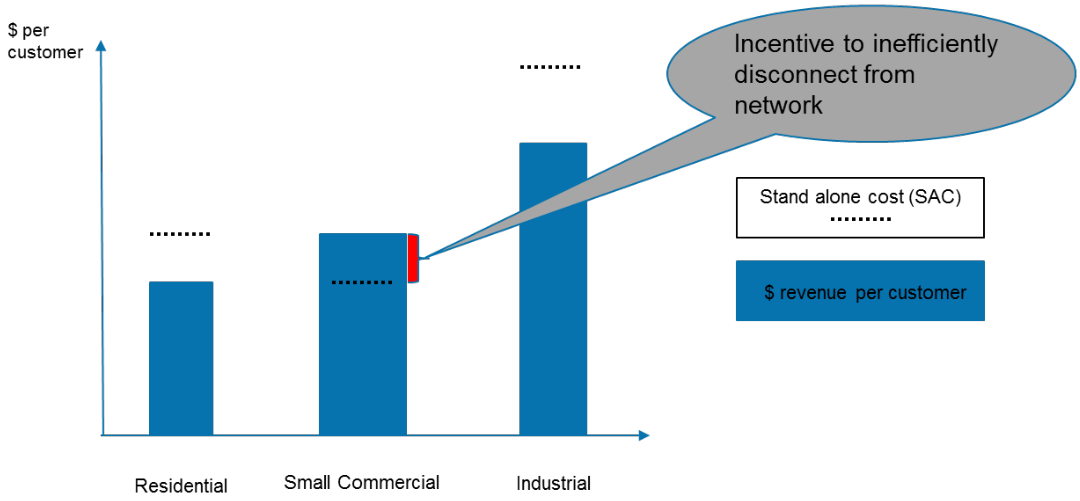
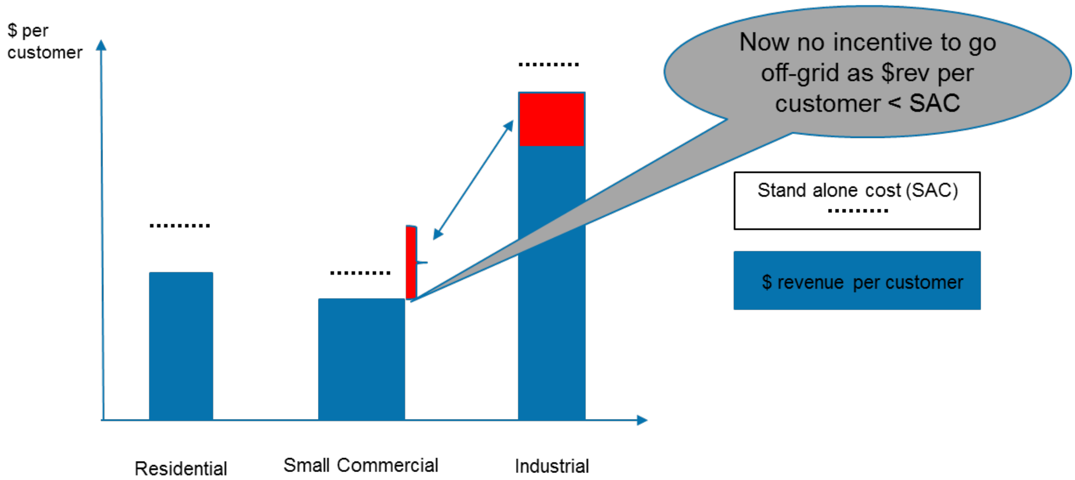


Figure 3: How a distribution business would respond if it thought its customers might inefficiently disconnect from its network



In short, changes to the transmission pricing arrangements need not lead to inefficient disconnections from a distribution network, wherever a distribution network can rebalance its tariffs to remain within the standalone cost threshold. Given the relatively small contribution transmission prices make to final retail bills (and the wealth transfer stemming from the proposed changes), and the large gap between most customers' standalone cost and their retail bills (predominately reflecting the natural monopoly characteristics of electricity network businesses), this risk is not considered material.

In the case of large directly connected customers and large customers indirectly connected via a distributor, if there was a risk that any wealth transfer might lead a customer to inefficiently disconnect from the grid, then, by design, the PDP mechanism as was original proposed would provide an additional protection mechanism.

- **Assumptions around retail charges:** In the context of the RCPD benefit, we did not make any explicit assumptions regarding retail charges. A more detailed discussion of issues related to retail pricing assumptions is contained in section 22 of this report.

- **The AoB charge does not provide an effective price signal to influence change in customer behaviour**: In their submission, Pioneer note that "*the assumption that existing demand response will respond to the proposed AoB charge is fundamentally flawed as the AoB charge does not provide an effective price signal to influence change in customer behaviour in response to that price signal. However, while we expand on this point in our main submission* ***it is acknowledged that this is somewhat subjective in the context of this submission on the CBA*** [emphasis added]". As Pioneer acknowledges, this is a subjective statement. As we stated in our original report, and in other parts of this report (e.g., section 14) it is not clear to us why load control, DR, DG etc that has been incentivised under the existing RCPD charge, and which is considered efficient, would not continue to be efficiently utilised in the future under the AoB charging arrangements. The same applies for new load control, DR, DG etc that is efficient. Moreover, the Guidelines provide Transpower with the option of introducing an LRMC based charge in the future, presumably if issues with the AoB charge are revealed over time.
- **ACOT payments**: We acknowledge that our CBA analysis (in particular, the cost of existing DG) was informed by an estimate of the historical ACOT payments. We used what we thought was the most up-to-date figure. Taking the comments by Pioneer on face value, if there is a more up-to-date figure, then this could feasibly be reflected in the CBA analysis, although we note that Pioneer's own assessment is that the change would lead to only a relatively immaterial change in the result ($3m).
- **The net costs from removing an effective peak demand signal are conservatively estimated to exceed $500m/y, or $5b in equivalent NPV terms:** In reading the Pioneer submission, they state that the "*presence of a peak demand signal enables an efficient market response that in aggregate delivers lower overall wholesale electricity market prices".* Based on this, it appears that Pioneer's contention is that removing a peak demand price signal (the RCPD charge) would lead to inefficient wholesale market outcomes.

  It is not clear to us why removing the RCPD price signal could or would lead to inefficient outcomes in the wholesale market. This is because the RCPD price signal is a *variable transmission* price signal that does not reflect the forward looking costs of providing transmission services. On face value, the reverse should occur, as by moving to the AoB arrangement, the market for generation will be incentivised by efficient price signals in both the generation market and the transmission market, whereas currently, the market for generation is in theory distorted by the ability for DG providers to capture benefits (via the RCPD) that exceed the actual benefits they provide to the transmission network.
- **A "punitive" benefit from tariffing sunk assets to beneficiary parties – an unheard of economic benefit (Vector)** – It is not clear to us what this "punitive benefit" is (it is not a term we used in our report). More generally, if Vector is in fact referring to how we have treated the reallocation of the costs of historical investments in our modelling, the reference to the term "benefit" is not correct. Rather, what we have said in the report is that the way sunk investments are recovered will in fact *not* impact economic efficiency, *unless* it:
  - Distorts the future usage of the existing network (e.g., consumption decisions); and
  - Leads customers (including generators and distributed generators) to make inefficient connection, disconnection or other investment decisions.

  A more accurate description of our modelling is that absent breaches to one or both of the above threshold tests, we assume there is no direct benefit from '*tariffing sunk assets to beneficiary parties*'.

- **Lower probability of (larger grid connected) customers disconnecting from the transmission grid**: The actual statement made by the ENA is: "*the ENA has concerns about the quantum of the CBA benefits ($90m NPV) that are realised by removing the RCPD signal from the interconnection charge when recovering sunk costs. The bulk of this benefit is realised from the lower probability of (larger grid connected) customers disconnecting from the transmission grid under the proposed TPM because their new charges would be less than under the existing TPM. The difference in charges is counted as a "producers' surplus" benefit to the customer and can be supplemented with a PDP as required. It appears that it is a transfer to consumers with no net benefit*." Firstly, the bulk of the benefit is **not** due to the lower probability of (larger grid connected) customers disconnecting from the transmission grid under the proposed TPM because their new charges would be less than under the existing TPM. Rather, it is primarily driven by our analysis that the RCPD incentivises, and will continue to incentivise, investments that are otherwise not efficient (i.e., investments that are more expensive than the transmission option they are displacing), and that the alternative TPM proposal will facilitate the recovery of residual costs including historical investments in a way that does not distort future consumption or investment behaviour. Therefore, the ENA's statement reflects an incorrect interpretation of our analysis of the RCPD charge. Notwithstanding this, the ENA's comments appear to be focused on the analysis of the PDP. We discuss this in detail in section 21.

11. Modelling errors

11.1. Summary of the issues raised on modelling errors

The Authority has asked us to consider assess two potential modelling errors raised by respondents. The specific comments that the Authority has asked us to consider are:

- The total annual demand tab of the Generation LRMC model, columns AP, AQ and AR do not match the sum of the inputs in previous columns, nor does the total New Zealand demand in AP equal the sum of North Island and South Island demand in AQ and AR (PwC), and
- Selection of 30-year timeframe – when all other benefits are over 20 year (Trustpower)

11.2. Response to the issues raised on modelling errors

In order:

- Total annual demand tab: This reflects information provided by the Authority on forecast energy loads (which we understand was sourced from Transpower). As such, we will revert to them to confirm the veracity of the information provided.
- Selection of 30-year timeframe: All of the base case results were undertaken over a 20-year time horizon, except for the analysis of the SIMI charge, which we noted in the report was undertaken over 30 years. Given this represents only around $13m in benefits, this is not considered material.

12. Benefits not assessed

12.1. Summary of the issues raised on benefits not assessed

The Authority has asked us to consider a number of issues raised by respondents highlighting benefits that they believe we have not assessed (or should have quantified). The specific comments that the Authority has asked us to consider are:

- CBA should consider scope for more efficient repairs and replacement (Oji Fibre);
- Greater incentive for customers to reveal their willingness to pay (BusinessNZ);
- CBA base case under-estimates increased scrutiny benefits (Meridian);
- CBA did not consider how service and cost reflective infra-marginal prices:
  - Would provide better information for decision-making;
  - Reduce economic barriers to the efficient ownership of sub-transmission assets (NZAS); and
  - Contribute to achieving the Authority's objective for durable charges by making the charges less unfair (NZAS).

12.2. Response to the issues raised on benefits not assessed

There are a number of comments in relation to this issue which we have grouped by theme in order to efficiently address the underlying issue/question:

- **CBA should consider scope for more efficient repairs and replacement**: Our reason for not including repairs and replacement is outlined on page 28 of our original report. In particular, we stated[16]:

  The material area of capital expenditure where we believe that there is some uncertainty around whether or not there will be a material economic benefit from sending a price signal that is linked to future expenditure is for asset replacement.

  On one hand, our experience is that the efficient timing of an electricity network's forecast replacement expenditure is generally not materially affected by the demands (or behaviours) that are placed on their network by end customers; rather, it is predominately driven by condition and risk factors unrelated to the loads (or behaviours) placed on the asset. This means that the efficient timing is unlikely to be materially influenced by end customer behaviour. The role of the regulatory framework is critical in this matter and is discussed further in the next section.

  On the other hand, the sizing and other technical features of the replacement solution may be influenced by the decisions and behaviours exhibited by downstream parties. For example, the sizing of a replacement transformer is likely to be linked to the demands expected to be placed on that transformer. However, the benefit, in this context, is the incremental change in costs between the "fully" sized transformer, and the "downsized" transformer, which will be significantly impacted by the economies of scale (or the loss thereof, in this case) associated with making that investment. This diminishes the likelihood that an alternate option is likely to be an economically feasible alternative to the replacement of an existing asset.

  We have not seen any information that would lead us to revise this component of the CBA.

16 OGW, Cost Benefit Analysis of Transmission Pricing Options, May 2016, page 28

- **Greater incentive for customers to reveal their willingness to pay / CBA base case under-estimates increased scrutiny benefits / Would provide better information for decision-making:** Conceptually, we agree with the general themes contained in the respondents' comments. As we stated in our original report, a possible benefit could arise from the introduction of the AoB charge if it led customers to "*scrutinise Transpower's proposed suite of investments in more detail, in particular, to assess whether those investments were consistent with their willingness to pay for the services that are provided as a result of those investments*[17]". However, we also described the intervening regulatory process that is designed to facilitate outcomes that are in the long-term interests of consumers, in light of the issue of asymmetric information. That is, Transpower will have more or superior information compared to the Commerce Commission and its customers in relation to the assets that it currently uses to provide those customers with Transmission services, as well as any new augmentation options/solutions that may allow them to provide services in the future.

  Overall, we are not dissuaded from our original statement that "*this benefit is inextricably linked to the robustness of the regulatory regime, the Commerce Commission's enforcement of that regulatory regime, and the extent to which the regulated WACC received by Transpower's exceeds its actual WACC by around 2.5% -- all parameters that we are unable to reasonably quantify. As a consequence, we have incorporated the benefit from increased scrutiny as an unquantified benefit, and undertaken sensitivity analysis to indicate its possible magnitude. This is a conservative assumption. Importantly the CBA is positive under this conservative position*[18]".

- **Reduce economic barriers to the efficient ownership of sub-transmission assets (NZAS):** Presumably, the respondent is implying that the proposed TPM will lead to Transpower having to reveal the cost it incurs in owning and operating sub-transmission assets, and that this revealed cost may incentivise more efficient owners/operators of those assets coming forward. If so, conceptually, this is a possibility, however, in thinking about the likely magnitude of the potential benefit, we were of the view that Transpower should have a number of advantages over potential new entrants into this market, given its current dominant market position (as the transmission operator covering NZ), as well as its current scale and scope, all of which should flow through to its cost structure. As such, we did not see this is a material benefit, notwithstanding that it is conceptually a benefit of adopting the proposed TPM.

- **Contribute to achieving the Authority's objective for durable charges by making the charges less unfair (NZAS):** As a concept, we generally agree with the proposition put forward by NZAS; in fact, we assumed that there would be a reduction in dispute-related costs going forward under the new TPM, with this based on the assumption that it would be fairer and therefore more durable.

17 OGW, *Cost Benefit Analysis of Transmission Pricing Options*, May 2016, page 30

18 OGW, *Cost Benefit Analysis of Transmission Pricing Options*, May 2016, page 30

13. Reliability/Security of supply dis-benefits were not assessed

13.1. Summary of issues raised in relation to reliability / security of supply dis-benefits

The Authority has asked us to consider a number of issues raised by respondents in relation to perceived reliability / security of supply dis-benefits. The specific comments that the Authority has highlighted are:

- The deferral of investments will increase the risk of investments being made too late and thus power outages happening more frequently. The CBA should also quantify the risk of investments not going ahead and thus outages occurring (PwC);
  - additional investment in substitutes; and
  - estimated benefits of investment in diesel based on a hypothetical worked example: a 10MW diesel generator employed at various locations.
- The CBA should explicitly consider the costs associated with a potential reduction in reliability from implementing and AoB charge (MRP); and
- elected not to consider…risk to security of supply…regional development (Vector)

13.2. Responses to the issues raised in relation to reliability / security of supply dis-benefits

As a general comment, a number of respondents argue that the AoB charge will lead to a reduction in reliability, presumably by forcing (or incentivising) Transpower to make investments "too late", thus leading to "power outages". For example, PWC states that[19]:

> *The CBA assesses the assumed benefits from investments being deferred. However, the deferral of investments will increase the risk of investments being made too late and thus power outages happening more frequently. The CBA should also quantify the risk of investments not going ahead and thus outages occurring,*

Firstly, the CBA estimates the benefits of deferring investments, however the deferral is predicated on *investments in alternatives to a transmission investment*. Simply suggesting that the CBA assumes investments are deferred, without referencing the assumption that there is an alternate solution that facilitates the deferral, is not correct. Moreover, it is not clear from the statement above, what specific aspect of the AoB arrangement would systemically lead to "*investments being made too late*" in an economic sense, noting that it may in fact be efficient to spend money to defer an investment, in theory even if this means that parties take on slightly more energy at risk (if the net deferral benefit exceeds the increased value of energy at risk).

19 PWC, "*Submission to the Electricity Authority on Transmission Pricing Methodology Review: Second issues paper; and Distributed Generation Pricing Principles*" - PwC submission on behalf of a group of 14 EDBs, 26 July 2016, page 19

Given that Transpower still has carriage of its own transmission program (i.e., it is the organisation making the final decision on what transmission assets are built), and the parties who will bear the consequence of any loss of supply[20] will be the ones subject to the AoB charge, any decision to defer will presumably reflect each party's view regarding risk and therefore should be efficient. In short, it is not clear to us why the AoB charge, would, based on its particular characteristics, systemically lead to an inefficient assessment of the cost of energy at risk, or the costs of alternatives to transmission investments, hence why we have not quantified this issue.

Regarding the reference made by Vector to the fundamental impact that the TPM may have on regional development, we confirm that we have given no consideration to this issue as part of our CBA. Rather, we have limited our assessment to the efficiency of the TPM charges, in the context of the electricity industry. We have been advised by the Authority that this aligns with their interpretation of their statutory objective.

14. Loss of price signal dis-benefits were not assessed

14.1. Summary of the issues raised on loss of price signal

The Authority has asked us to consider a particular issue raised by a respondent related to dis-benefits resulting from a loss in the price signal. The specific comment was:

- An absence of benefit attributed to the current RCPD incentive effects, for load control (NZ Steel)

14.2. Response to the issue raised on loss of price signal

Based on the comment above, it appears that the respondent is of the view that the removal of the RCPD price signal, and its replacement with the AoB charge, will lead to the inefficient (non) use of existing load control in the future.

On the assumption that our interpretation of the respondent's comment is correct, we would first note that we understand why this is a legitimate concern of stakeholders, however, the assumption underpinning the CBA is that any load control that is efficient will continue to be utilised in the future under the TPM proposal.

More specifically, if load control is currently being incentivised under the existing RCPD charge, and the marginal cost of continuing to operate that existing load control into the future is less than the cost that a business would incur in the future as a result of the levying of the AoB charge for a new transmission asset/s[21], then that business would be incentivised to continue to operate that load control in response to the AoB price signal[22].

Therefore, in summary, it is not clear to us why load control that has been incentivised under the existing RCPD charge, and which is efficient, would not continue to be efficiently utilised in the future in response to the AoB price signal.

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20 Whether directly, or indirectly by way of their relationship with the end customers who are connected to their network.

21 Which, based on the proposal, will reflect of the beneficiaries share of the costs of the transmission asset being built, as well as a marginal cost adjustment price signal.

22 Note that if there is an issue with parties not responding to the AoB charge, then the broader proposal provides Transpower with the ability to introduce an LRMC charge, which would address the problem.

15. Wealth transfer dis-benefits were not assessed

15.1. Summary of the issues raised on wealth transfer dis-benefits

The Authority has asked us to consider a particular issue raised by a respondent related to dis-benefits resulting from wealth transfer. The specific comment we were asked to address was:

- No efficiency loss (or inefficient reductions to demand) from wealth transfer (Transpower).

15.2. Response to the issue raised on wealth transfer dis-benefits

As we stated in our report, our interpretation of the Authority's statutory objective is that[23]:

> *'the Authority must focus on economic efficiency, as opposed to the distributional impacts (ie, wealth transfers) that might stem from a change in transmission pricing arrangements (unless they impact upon efficiency). We have adhered to this approach when developing this CBA.'*

In short, from an economic efficiency perspective, we are not concerned with wealth transfers *per se*, but rather, whether the change in transmission pricing arrangements that lead to that wealth transfer, also lead to inefficient outcomes. In the context of the CBA, we think we have been quite clear about the framework within which we have made this assessment, in particular, we have considered whether:

- the marginal price signal reflects forward-looking costs, so that the price signal incentivises all market participants to make efficient future consumption and investment decisions in response to that component of the charging arrangement; and
- the way in which residual costs including the costs of historical investments are recovered distorts future consumption or investment behaviour.

In relation to the latter, we further stated in our original report (and discussed earlier in this report) that subject to two provisos, the way in which residual costs and the costs of historical investments are recovered should not materially influence economic efficiency, as these costs are fixed or have already been incurred, and therefore, cannot be reversed. The two provisos are that the recovery mechanism minimises the extent to which the recovery of those costs[24]:

- Distorts the future usage of the existing network (e.g., consumption decisions); and
- Leads customers (including generators and distributed generators) to make inefficient connection, disconnection or other investment decisions.

More directly to the point raised, as discussed in the CBA report[25], the reason that we have not assumed any reduction in economic efficiency from the reallocation of costs – and resultant wealth transfers – through inefficient reductions in demand is summarised as follows:

23 OGW, *Cost Benefit Analysis of Transmission Pricing Options*, May 2016, page 19

24 OGW, *Cost Benefit Analysis of Transmission Pricing Options*, May 2016, page 23-24

25 The CBA should be referred to for more detail on this issue.

- In relation to future investments covered by the AoB charge, as we stated in our report (section 7.2.1), whilst the AoB charge would lead to the costs of an eligible future investment being recovered after the investment is made, in our opinion, this doesn't necessarily dilute the effectiveness of the price signal (i.e., it is still an efficient *ex-ante* price signal for future investment), as long as customers[26]:
  - **Understand there is a clear link between their actions and the incurrence of those future cash flows, prior to them undertaking the action**: Based on the evidence that the Authority has presented to us, we have no reason to believe that this threshold test would not be met, as the AoB process itself will (a) inform customers that they are a beneficiary of a specific investment, (b) inform them of their charge, as it relates to that asset, (c) inform them of the basis for the charge (i.e., the factors that have been considered when developing their share of the costs of that asset), and under the original proposal (d) the marginal cost adjustment, being the benefits that they will receive if they reduce their demand at the margin for the services provided by that asset;
  - **Are sent the price signal with enough lead-time to enable them make the necessary changes in their own investment or consumption behaviour in response to that price signal, and have these changes flow through to the costs Transpower incurs**: With regards to this, in our opinion, the process for calculating the AoB charge by necessity, means that parties subjected to the charge will be made aware of the charge with a reasonable lead time. Moreover, if this is not the case, one would presume that in fact Transpower itself would respond to its customers' requirements by extending this lead time; and
  - **Are not incentivised to change their behaviour after the investment has been made, in order to change the future stream of payments that they must make so that Transpower can recover the costs of that investment (that is now already made)**: With regards to this, in our opinion, this threshold test is met, due to the means by which historical investments are recovered, in particular, once an investment has been made, there is little scope under the arrangements that were proposed for the beneficiary to change their behaviour *ex post* to reduce that part of their transmission bill that is used to recover those historical investments. This is discussed in more detail below.
- In relation to the reallocation of residual costs and including the costs of historical investments, as we stated in our original report, we believe it is reasonable to assume that this reallocation will not lead to any materially inefficient outcomes for the following reasons:

26 We also stated that "*For the purposes of this CBA, based on the information provided by the Authority, both of the proposed transmission pricing options in our opinion, appear to meet these threshold tests. If any of these factors do not hold true, the benefits described and quantified in this CBA will exceed those that will occur in practice.*"

  - The Authority proposed to recover residual costs from load customers, with this being based on each customer's physical capacity, and that physical capacity would be determined on the basis of one of the following: (a) transformer capacity; (b) line capacity; or (c) anytime maximum demand (AMD). The first two are set (i.e., future decisions will not influence them), therefore, they will not affect marginal consumption or investment decisions, and subject to not breaching the customers' willingness to pay for transmission services in totality, would not incentivise them to inefficiently disconnect from the network. While the latter (AMD) is not a physical measure *per se*, and in theory, could affect a customer's marginal consumption and investment decisions, it was our understanding at the time of developing the CBA that a customer's AMD would be determined based on their average maximum demand in each of the 5 years leading up to the date of release of the draft second issues paper, and it would only be updated with a 10-year lag. Both factors are likely to mean that it is very difficult for customers to avoid in the future, and provide for the charge to reflect a customer's reliance on the transmission system, both of which mitigate the risk that a customer may alter its AMD to affect this charge. For new customers, at the time of developing the CBA, it was our understanding that the Authority was proposing that Transpower develop methodologies for dealing with the entry of new load customers, with the aim that they face residual charges similar to comparable load customers. This basis of charging would appear to us to not comprise economic efficiency – because it decouples the charge from the customer's marginal investment and consumption decisions. Overall, this led us to assume that there would be no materially inefficient transmission price signal stemming from the change in how sunk investments are recovered[27].

- Further to the above:
  - As we stated in the report[28], the adoption of the AoB approach to recover some historical investments will also link the recovery of those sunk costs to an assessment of who has benefited from the construction of that asset. We consider that this will reduce, but not necessarily eliminate, the risk that prices will breach the stand alone and avoidable cost tests – which is the fundamental test as to whether the adoption of this essentially fixed charge will lead to inefficient future connection or disconnection decisions;
  - Distribution businesses have significant scope (and a commercial incentive) to rebalance their own charges to ensure that the way in which they recover transmission charges does not inefficiently incentivise their customers to disconnect from their network (see section 10 for a more detailed discussion of this concept); and
  - The introduction of a more comprehensive PDP, as was modelled as part of the original CBA, would provide a further means for Transpower to adjust its charges to customers that are at risk of inefficiently disconnecting from the transmission network as a result of any reallocation of the recovery of the costs of sunk investments. This would provide further protection against customers who are subject to the new AoB charge, inefficiently disconnecting from the network[29].

27 OGW, *Cost Benefit Analysis of Transmission Pricing Options*, May 2016, page 46

28 OGW, *Cost Benefit Analysis of Transmission Pricing Options*, May 2016, page 26

29 OGW, *Cost Benefit Analysis of Transmission Pricing Options*, May 2016, page 27

More generally, the concern expressed by Transpower appears to stem from advice it has been provided by Axiom Economics. In reviewing Axiom Economics' report, the core issue raised, as it relates to the issue of the efficiency impacts of wealth transfers, appears to be captured in the following paragraph:

> *However, it is conceivable that the introduction of the [AoB] charge would give rise to a material reduction in static efficiency. This could stem from the very large shifts in the allocation of sunk costs onto load customers. The most striking example is the reallocation of existing HVDC costs.*
>
> *Under the indicative modelling in the Issues Paper, South Island generators would continue to pay around half the HVDC costs – but the other half would switch to load; primarily to customers located in the North Island. The net present value (NPV) of that transfer would be around $750m over the 20-year assessment period in the CBA (around $65m per annum). The efficiency benefit that is said to arise from this reallocation is $13m, i.e., less than 2 per cent of the wealth transfer.*
>
> *It would require only a small demand response on the part of those load customers to offset the $13m estimate. For example, if those additional transmission charges were passed-through even only partly as volumetric charges to end customers (i.e., if distribution businesses moved to more efficient pricing methodologies), and this caused even a small reduction in the use of those existing assets by those load customers, then the resulting allocative efficiency loss would, in all likelihood, be much larger than $13m over a 20-year period.*
>
> *At the very least, it is not reasonable to assume that such large wealth transfers (around an additional $850m on load customers in total) would have no impact on allocative efficiency – which is the position adopted in both the Issues Paper and the CBA. It is not obvious therefore that there are material allocative efficiency gains that could be delivered via an AoB charge, but there does appear to be significant potential for allocative efficiency losses.*

Firstly, as Axiom Economics states, it is "conceivable", but this does not make it likely (or even remotely likely). For such reduction or loss in allocative efficiency to occur implies that distribution businesses would structure their tariffs so that their now fixed transmission costs are recovered from customers via a variable charge. Our view is that pricing in this way would be inconsistent with economic theory. This also may make little commercial sense, if it exposes that business to volumetric risk (because its marginal prices differ to its marginal costs). In short, the outcome "conceived" is not a direct function of the wealth transfer *per se*, but rather a function of the (inefficient) tariff structures that are assumed to be adopted by the distribution business in response to that wealth transfer.

16. Cost of capital dis-benefits were not assessed

16.1. Summary of the issues raised on cost of capital dis-benefits

The Authority has asked us to consider a particular issue raised by a respondent related to the potential for there to be cost of capital dis-benefits. The specific comment we were asked to address was:

- Material impact on the cost of capital for future investment. This will flow through directly to investment costs and to the cost of electricity, and must be accounted for by the Authority in its assessment of the long-term benefits to electricity consumers. (Infratil)

16.2. Response to the issue raised on cost of capital dis-benefits

To give context to the issues raised, we have repeated the specific comments made by Infratil in their submission[30]:

- *If the Authority proceeds with its proposals to reform the TPM and remove the DGPPs, it could result in not just a significant (and potentially total) reduction in ACOT payments, but an unknown and potentially material increase in the connection charges paid by Trustpower's distributed generation schemes. This will lead to the following impacts on Infratil's ongoing support of Trustpower:*
  - *We will be significantly more conservative in our approach to investing in the New Zealand electricity generation sector and, if we do invest further, will apply extra conservatism into our assumptions about the regulatory environment.*
  - *This will have two main effects: (a) it is likely to delay or permanently defer the build of new generation; and (b) require us to apply a higher cost of capital to take account the higher level of investment risk. Both outcomes are poor for both consumers and investors. Delays in adding generation capacity will likely lead to higher electricity prices for consumers, for longer. And the delays or permanent deferrals will deny investors the opportunity to achieve fair rates of return on capital. In other words, our desire for future investment will be "chilled".*
  - *We will choose to shift capital towards investments in sectors which we see as being governed in a more "investor-friendly" way, such as the Australian renewable energy market. Whether other investors fill the New Zealand gap, would be uncertain. However, it is worth noting that when we observe, in foreign markets, reticence to invest by experienced and knowledgeable local investors, we become wary ourselves in investing and assume there is a higher degree of risk. That is a poor outcome for consumers.*
- *In summary, changes such as those proposed, without sufficient appreciation for the expectations of existing investors, will have a material impact on the cost of capital for future investment. This will flow through directly to investment costs and to the cost of electricity, and must be accounted for by the Authority in its assessment of the long-term benefits to electricity consumers.*

At a conceptual level, we agree with Infratil that decisions around how networks are priced (and particularly when large changes to those pricing arrangements are proposed), could theoretically impact on the risk appetite of investors to make investments in assets that are affected by those pricing arrangements. However, in reading Infratil's submission, the important issue we see is: "what is the source of that risk"? Is it the:

- Uncertainty ('*the unknown, and potentially material increase in the connection charges paid by Trustpower's distributed generation schemes*');
- Risk that the Authority might "*proceed with its proposals to reform the TPM **and** remove the DGPPs* [**emphasis added**]"; or
- Change to the TPM itself.

In the context of the latter, which is the focus of our CBA, we are of the view that investment risk would be compounded if:

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30 Infratil, *Letter to Carl Hansen*, 25th July, 2016, page 2-3

- The arrangements are overly flexible, thus creating uncertainty around the actual decisions that will manifest as a result of the implementation of the arrangements;
- Industry participants might reasonably believe that the arrangements will be subject to either regular or ad hoc re-opening (i.e., changes)[31]; or
- The proposed arrangements are manifestly inconsistent with economic theory, or manifestly unfair or unreasonable, which in turn is likely to drive more disputes and increased risk of re-opening.

At the time of developing the CBA, we did not consider any of the aforementioned conditions to be met, therefore, we had no reason to believe that the proposed TPM arrangements *themselves* would increase the risk premium associated with investing in the New Zealand electricity industry in the future. To the extent that any individual participant sees higher charges and changes their investment decisions it is important to note that a core role of pricing is to do precisely that, i.e. to influence future decisions and all pricing structures will do that in one way or another. The key to successful design or amendment of pricing structures is to create or improve incentives for efficient decisions. Improvements in incentives may change decisions of individual players and may shift the balance between transmission, distribution and customer investments or between technologies. Providing the result is economically sound the pricing structure will have done its job. Any discussion of the broader decision-making process, the impact of combined changes etc, is beyond the scope of our project.

17. Administration and implementation costs were too low

17.1. Summary of issues raised regarding administration and implementation costs

The Authority has asked us to consider a number of issues raised by respondents related to the administration and implementation costs that were assumed. The specific comments that we were asked to give consideration to when making our response were:

- Up-front costs included in the CBA are limited to those borne by Transpower and the Authority (Genesis, Castalia). Ongoing costs included in the CBA are also limited to Transpower,
- Proposal introduces substantial scope for disputes, legal challenges and delays, which should be reflected in the CBA (PwC) reveals a real lack of comprehension of the nature of the proposal being put forward and how participants will respond to it (PwC),
- For Transpower to only require 3 additional FTEs to establish the new TPM seems very optimistic (PwC),
- More bilateral arrangements required (Pioneer),
- Costs involved with implementing new consultation schemes aimed at facilitating the anticipated process are likely to be substantial, and well in excess of the incremental total present value cost of $3.5 million estimated by Oakley Greenwood (Trustpower), and
- Potential for lobbying is exacerbated by the marginal adjustment mechanism (Trustpower)
    - in trying to send appropriate marginal cost signals, the EA's proposal can lead to perverse outcomes

31 Note that this is not to say that they should, or can never, be changed.

  - if firm A could offset its entire proposed demand increase to 0 kVA though demand response, under the EA's proposal it would continue to contribute about $200 to the overall costs of the network augmentation despite not benefiting from it at all. This highlights the fact that in trying to send appropriate marginal cost signals, the EA's proposal can lead to perverse outcomes;
  - this example serves to show that in general customers will not benefit from signalling interest in an investment and then identifying options for demand management. This could result in the customer paying more per unit of capacity than it would if it sought options for demand management prior to discussing network augmentation with Transpower; and
  - conversely, customers may benefit even further by delaying signalling interest in an investment until it has been proposed by other parties. Under the process proposed by the EA, customers that subsequently signal interest in the investment may be able to pay for the benefits that they receive at the marginal price, rather than the average price. (Trustpower).
- The CBA fails to take into account the fact that other elements, not the least being the LRMC element, may need to be incorporated in the future at cost (NZ Steel)
- The CBA has failed to take into account how distributors and retailers will interact (e.g., the transaction costs arising from distributors needing to renegotiate contracts with direct-billed customers) (Alpine Energy).

17.2. Responses to issues raised on administrative and implementation costs

The issues highlighted by the Authority indicate that some respondents consider our assessment of the costs to be too low.

Firstly, any assessment of costs is likely to be quite subjective in nature, so it is to be expected that different parties might have different views as to the costs of administration and implementation. In this context, there is no further empirical information contained in the comments above, hence, it is difficult to draw any definitive conclusions from them one way or the other.

That said, given the nature of the comments, it is important to emphasise that we have modelled the *incremental costs of the TPM proposal* – that is, the additional costs that will be incurred, as compared to the base case. It is for this reason that we limited our assessment of up-front costs in the CBA "*to those borne by Transpower and the Authority (Genesis, Castalia) and "ongoing costs included in the CBA are also limited to Transpower*", because:

- Transpower and the Authority are the parties that will have to actually set-up the TPM; as receivers of the transmission price signal, it is not clear to us why any other party would need to incur any material increase in cost *upfront,* to prepare for the AoB charge; and

- In the longer term, whether it is an RCPD, AoB or any other form of transmission charging regime, existing transmission customers will continue to use existing resources to continue to engage with the TPM on a day-to-day basis into the future. Whilst this is not to say that every transmission charging regime has the same level of complexity, on face value, there is no particular feature of the AoB that makes it so different as to materially change the resourcing required to deal with the charging mechanism on a day-to-day basis (e.g., billing systems, calculating transmission charges, explaining transmission charges to internal and external stakeholders), hence it seemed reasonable to us to assume that this engagement (and therefore level of resources) will not be materially different under the new TPM as compared to the old TPM. Finally, presumably many of the on-going costs incurred by all parties are driven by review processes such as this one. These (likely quite material) costs are already being incurred, and therefore are implicitly assumed to be reflected in the base case.

Furthermore, we note PwC's actual comments regarding disputes are:

> *Any new TPM will require new decisions that will result in winners and losers. Irrespective of the merits of a new TPM proposal, the most likely outcome is that a change will result in some challenges, at least initially as parties test the decisions being made. The TPM as proposed by the Authority appears particularly at risk of creating disputes because of the sheer number of decisions and judgement calls Transpower has to make (listed above). Additionally, as this new TPM will make some parties materially worse off, possibly even to the extent of making some businesses unviable, any legal action that can delay the application of the new TPM may be attractive to certain transmission customers. The distributors which support this submission do not think it is credible to argue the proposed TPM will lead to reduced disputes and a CBA that does not include these costs is also not credible. Whatever the merits of the proposed TPM, the novelty of the arrangements, the level of discretion and the financial impacts on transmission customers make disputes a near certainty. This should be recognised by the Authority and incorporated into the cost benefit analysis….*

and that

> *"the CBA includes an assumed benefit from reduced dispute costs. As discussed above this is simply implausible and reveals a real lack of comprehension of the nature of the proposal being put forward and how participants will respond to it".*

Firstly, PwC is right that any new TPM will require new decisions that will result in winners and losers, however it is not clear what evidence PwC has based its assertion that the TPM may make "some businesses unviable", or for that matter, what component of the TPM is driving this. More broadly, it is unclear what aspect of the arrangements would lead PwC to draw the conclusion that the "the novelty of the arrangements" contributes to making disputes a near certainty. Most importantly, what the comments don't appear to have regard for is that the current arrangements are not costless with regard to disputes – there have been numerous reviews of the TPM, all, presumably are driven ostensibly because of the disconnect between those arrangements and the objectives underpinning those arrangements - and it is our understanding that there have been a number of disputes. These are all real costs, all of which are being incurred under the base case, and all of which are assumed to continue into the future, in the absence of change in the TPM arrangements.

Finally, we reiterate that this component of the CBA is quite subjective, hence why we undertook sensitivity testing within the CBA on this parameter. In particular, we tested the impact of doubling the costs. This showed that the CBA was still positive.

Regarding Trustpower's comments on the potential for lobbying being exacerbated by the marginal cost adjustment mechanism, without entering into the merits as to whether or not Trustpower's interpretation of the Authority's proposal is correct, we note that:

- Under the original proposal modelled, Transpower would be charged with developing the marginal cost adjustment rate that applies to its transmission investments, therefore, they presumably will not be particularly amenable to lobbying by any of their end customers, therefore, it is unclear why there would be additional costs stemming from this issue;
- Even "*if firm A could offset its entire proposed demand increase to 0 kVA though demand response*", if the cost of that demand response was less than the cost reduction that Firm A would receive as a result of the application of the marginal cost adjustment to that reduction in demand, then:
  - Firm A would still be incentivised to engage that DR, and this would be an efficient (and commercially sensible outcome) to adopt, as the DR is the lower cost option, relative to if Firm A did not enter into a contract for DR, and instead paid its full AoB charge (which would reflect the marginal cost to Transpower of catering for that additional load); and
  - Whether or not Firm A still has to pay $200 is, in theory, irrelevant to its marginal investment decision (to purchase DR or not, and therefore the impact of this decision on economic efficiency), because Firm A will still be responding to the marginal price signals.
- Even if a customer "*may benefit even further by delaying signalling interest in an investment until it has been proposed by other parties. Under the process proposed by the EA, customers that subsequently signal interest in the investment may be able to pay for the benefits that they receive at the marginal price, rather than the average price*", all customers still face an efficient marginal price signal in this situation, hence from an efficiency perspective, this would not appear to be an issue. Put another way, even if a customer delayed interest in an investment, and was only charged the marginal cost adjustment, it would assess whether it was willing to pay that marginal cost (which is the marginal cost of the transmission alternative) relative to the marginal cost of an alternative option such as DR of DG. Finally, it is not clear how this manifestly impacts on the costs of the proposal.

Regarding comments to the effect that the CBA fails to consider the fact that other elements, not the least being the LRMC element, may need to be incorporated in the future at additional cost. Clearly, further changes may add further costs, but we can only assume any further changes will be subject to further analysis (i.e., costs and benefits). That analysis would assess the incremental benefits and incremental costs against the status quo at the time they are proposed – presumably the proposed AoB and residual charge.

Regarding the costs of interaction between distributors and retailers, it is correct that the original CBA did not explicitly take such costs into account. The reason for this is that we judged them to be common to both the status quo and amended TPM, that is there would be no material incremental change. Distributors and retailers inevitably interact day-to-day, week-to-week etc under the current arrangements, hence it is unclear why, at a general level, these costs would materially change under the new TPM. In relation to the example provided (e.g., the transaction costs arising from distributors needing to renegotiate contracts with direct-billed customers), again, if this occurs at the end of an existing contract period, then it is not clear why the introduction of the new TPM would materially increase as a result of a new TPM.

If both parties were to elect to re-open a contract because of the change in the TPM arrangement, then presumably this would be done as there are private benefits accruing to both parties from this negotiation (hence this would appear to be outside of the scope of costs that are "required" to be incurred as a result of the change in the TPM arrangements). It would only be if the current contractual arrangements stipulated that contracts must be re-opened as a result of changes in the TPM that this would be relevant to our CBA. We have no reason to believe this is a material issue.

18. Other dis-benefits were not assessed

18.1. Summary of the issues raised regarding other dis-benefits not assessed

The Authority has asked us to consider a number of issues raised by respondents relating to a number of other perceived dis-benefits that were not assessed. The specific comments we were asked to address are:

- The Authority is silent on how functionless rents should be treated. Even if only the functionless rent component of the price impacts were taken into account the amount would likely exceed the estimated efficiency benefits (Powerco. p.3)
- Economic distortions arising from recovering charges for sunk assets over fewer parties (Vector)
- Ignores competition effects on in generation (NZ Energy)
- Whether the AoB may have wholesale market efficiency implications in terms of the efficiency of the location of new generation (BusinessNZ)
- Exclusion of deadweight losses in assessing costs and benefits of higher prices leading to a decrease in quantity (Trustpower)
- No examination of distribution costs and benefits that would support an assessment of the certainty of its estimates of net benefits (Trustpower)
- Uncertainty should be appropriately accounted for in estimates made of future costs and benefits (Genesis, Castalia)
- There is a high risk of adverse impacts in the short to medium term that the Authority has not taken into account. Regardless of the long to medium term benefits once the methodology stabilises, the costs in the short to medium term could be high (ENA)

18.2. Response to the issues raised regarding other dis-benefits not assessed

The Authority has highlighted a number of disparate issues, therefore, we have responded briefly to each one:

- **Functionless rents:** This is based on a statement in Powerco's submission that the "*Authority has been clear it does not consider wealth transfers should be taken into account unless they have efficiency or durability impacts, but has been silent on how functionless rents should be treated. Even if only the functionless rent component of the price impacts were taken into account the amount would likely exceed the estimated efficiency benefits*[32]". Powerco has provided no information in support of this statement, for example, the basis for their assertion regarding functionless rents, how the magnitude of those rents has been estimated, how those functionless rents relate to the change in the TPM being proposed or whether they in fact result from other regulatory or institutional arrangements affecting the NZ electricity industry. Therefore, we cannot comment on the specifics of Powerco's comment, however, at a general level, it is not clear to us why the TPM arrangements, which prescribe *how* Transpower *recovers* its overall revenue requirement - not the overall magnitude of Transpower's revenue requirement, which is the process by which functionless rents could presumably accrue - could be reasonably be seen to lead to functionless rents (e.g., supra-normal profits that accrue to a monopoly service provider that neither arise from cost savings nor innovation);
- **Recovering charges for sunk assets over fewer parties:** The issue is not whether the cost of historical investments are recovered over a small or large number of parties *per se*, but rather whether the recovery of those costs will lead to inefficient future consumption or investment decisions. Earlier sections of this report (e.g., section 15) outline why we have not assumed there will be any efficiency loss stemming from the wealth transfers that result from substituting the current TPM for the proposed TPM;

32 Powerco, *Submission on Electricity Authority Transmission Pricing Methodology Review, Second Issues Paper*, 26 July 2016, page 3

- **Ignores competition effects in generation**: NZ Energy's specific comment on page 3 of its submission provides more context to this comment. This was: "*One of the statutory objectives of the EA is to promote competition. The EA does not believe all DG is inefficient so without argument some DG in EA's opinion is a true competitor to transmission and distribution. The TPM advisors Oakley Greenwood (OGW) has noted in their cost-benefit analysis that existing DG provides benefits to consumers, however. The TPM proposal is strangely silent on how the TPM proposal will promote efficient DG competition in transmission which will provide increased long term benefits for the consumer. In fact if the proposal results in any reduction in existing efficient DG plant then the result will actually be a decrease in competition and hence a failure by the EA to meet their statutory objective*". Firstly, it is correct that we noted in our CBA that based on our methodology, the continued operation of existing DG is likely to provide benefits to consumers. Furthermore, as we have stated previously (e.g., at the Wellington public forums; Section 14 of this report), if existing DG is efficient, we don't see any reason why in practice, it would not continue to be utilised in the future under the TPM proposal. More specifically, if DG is currently being incentivised under the existing RCPD charge, and the marginal cost of continuing to operate that DG into the future is less than the cost that a business would incur in the future as a result of the levying of the AoB charge for a new transmission asset/s (including the marginal cost adjustment), then that business would be incentivised to continue to purchase that DG such that it is deployed in place of the transmission investment signalled under the AoB charge. The same goes for new DG – if it is efficient, we see no reason why the AoB benefit price signal would not incentivise relevant parties to procure that new DG. All in all, the AoB charge should promote competition in generation, including DG, where it is the long term interests of consumers. Finally, it is noted that if there is an issue with parties not responding to the AoB charge, then the broader proposal provides Transpower with the ability to introduce an LRMC charge, which would also address the problem;
- **Wholesale market efficiency implications in terms of the efficiency of the location of new generation:** BusinessNZ has stated that Electricity Authority should "*assure itself of ….the extent, if any, to which the AoB charge may have wholesale market efficiency implications in terms of the location of new generation*". On face value, removing the RPCD charge and implementing the proposed AoB charge would positively impact on wholesale market efficiency in terms of the location of new generation, by way of:
  - incentivising the co-optimisation of transmission and generation investments (which we have modelled in our CBA);
  - removing any inefficient incentive regarding the location of generation resulting from the SIMI charge (which we have modelled in our CBA); and
  - the signalling of the true economic cost of future transmission assets, which affect the benefits of installing distributed generation which, when combined with nodal prices, in turn should lead to efficient decisions regarding whether or not to install large scale or distributed generation, and how it is operated.
- **Exclusion of deadweight losses in assessing costs and benefits of higher prices leading to a decrease in quantity:** See section 22 for a more complete discussion of this issue.
- **No examination of distribution of costs and benefits that would support an assessment of the certainty of its estimates of net benefits:** This observation is correct, however we undertook sensitivity analysis to determine whether or not, under a range of feasible outcomes, the CBA would remain positive (which was the case);

- **Uncertainty should be appropriately accounted for in estimates made of future costs and benefits**: Conceptually, we agree with the respondent that uncertainty should be accounted for in the analysis. This raises a question as to what is the appropriate means of achieving this. In our CBA analysis, we have addressed this matter by looking at the sensitivity of the base line results to feasible changes in a number of input parameters (i.e., we undertook sensitivity analysis). However, what we didn't do is to apply asymmetric adjustments to costs and benefits (e.g., universally higher costs and lower benefits) under the base case in order to account for this uncertainty, as this approach would imply that the uncertainty is skewed towards the downside (i.e., it is asymmetric). Our view is that this "uncertainty" is symmetrical, not asymmetric, hence our treatment of this uncertainty via sensitivity analysis.
- **High risk of adverse impacts in the short to medium term**: Whilst it is easy to link change with risk, and risk with adverse impacts, at a qualitative level, it is not clear to us what particular aspects of the TPM arrangements have led the submitter to make these comments. Moreover, adverse impacts do not necessarily lead to a loss in economic efficiency – the adverse impact may reflect someone's view as to the financial impact that the change imposes upon them, however this may not translate into a reduction in economic efficiency. For example, if the submitter is suggesting that the removal of a peak signal combined with significant wealth transfers means there is a high risk of adverse impacts in the short to medium term, then yes, some business may face adverse financial impacts. Any change to network tariff structures will inevitably lead to some customers being exposed to financial gains, and some to financial loss. However, it is unclear, even in this situation, how these adverse financial impacts negatively affect economic efficiency, noting that we have addressed issues around cost of capital dis-benefits, wealth transfer dis-benefits and loss of price signalling dis-benefits in previous sections of this report. Further, providing a charge is capable of delivering an improvement in economic efficiency, the 'quality' of implementation and transition processes can be critical in managing and mitigating risk of short to medium term adverse impacts. These are matters for the Authority and the industry in general to manage.

19. The counterfactual was incorrectly considered

19.1. Summary of the issues raised regarding the definition of the counterfactual

The Authority has asked us to consider a number of issues raised by respondents related to the definition of the counterfactual. The specific comments that we were asked to give consideration to are:

- TPM2 appears to compare the proposed change with the current status quo (MEUG NZIER)
- an inappropriate definition of the 'counterfactual'. The CBA assumes that the only way to obtain the estimated benefits is through the options it models (Transpower, Axiom).

19.2. Response to the issues raised as to the definition of the counterfactual

In response to the first comment, the modelling assumes that the TPM arrangements scheduled to commence on 1 April 2017 are in place.

In response to the second comment, the CBA *implicitly* assumes that the only way to obtain the estimated benefits is through the options it models. The word *implicit* is important, quite simply, because the Authority has only commissioned us to estimate the net benefits of those options – to be clear, we were not commissioned to develop other options, nor were we provided with any other options to model.

20. There were issues with the HVDC benefit calculation

20.1. Summary of the issues raised regarding the calculation of the HVDC benefit

The Authority has asked us to consider a number of issues raised by respondents related to the calculation of the HVDC benefit. The specific comments we were asked to consider are:

- The EA assumption about how much of the HVDC charge South Island generators are able to pass on under the business as usual scenario is not clearly stated (MEUG NZIER),
- A further $13m NPV benefit is assumed to be realised from the removal of the HVDC charge…This is a somewhat simplistic assessment as it does not reflect the additional AoB charges that would be faced by generators under the proposed TPM and that would also be taken into account in any investment decisions. We are also not convinced that the list of projects is realistic – for example, building the Rodney power station, which the modelling expects, would be inconsistent with current trends of thermal plants being shut down and renewable plants being built (PwC), and
- Benefit from removing SIMI ($13m): Adjusted LRMCs were used…and the MED model…the SIMI model has not been provided… it is not considered possible for the Proposal to produce both the More Efficient Generation Benefit and the SIMI Benefit to the extent that has been quantified (Pioneer)

20.2. Response to the issues raised regarding the calculation of the HVDC benefit

In order:

- **Assumption about how much of the HVDC charge South Island generators are able to pass on**: The full comment, for context is: "*The Oakley Greenwood CBA does not perform any additional analysis on the changes to the HVDC charges but simply takes the SIMI model output from the EA along with the Oakley Greenwood variations on the planned new generation plant forecast by the MBIE model. The old and new schedules seem to have similar orders of magnitude with small timing differences that deliver a small difference in net present value.*" The commentary made by the respondent is generally correct; we have taken the impact of the SIMI charge, and overlaid that on the future generation candidate plants to assess whether this changes the mix of plant that would be constructed, relative to a least cost mix of plant. Implicitly, it is true that this means that we have assumed that new plants located in the South Island are unable to pass on the SIMI charge. This was considered reasonable given the overall magnitude of the benefit ($13.7m), which means it would not have influenced the overall results of the CBA. Furthermore, if we were to model generators ability to pass through this cost, we would also extend this analysis to also model the (negative) impact that the SIMI charge has on the dispatch of existing South Island plants, and therefore economic efficiency (i.e., the SIMI charge leading to existing South Island generator/s not being dispatched, even though they are the least cost plant mix).

- **It does not reflect the additional AoB charges that would be faced by generators under the proposed TPM:** Any forward-looking network investment that is constructed to benefit a generator, no matter where they are located on the network, would be signalled to that generator via the AoB charge (assuming it meets the threshold), which would be efficient. The AoB charge, as it is applied to historical investments such as the HVDC link, will in part de-link the recovery of historical investments from future investment decisions, given the breadth of coverage of the AoB charge. This limits the impact that this charging approach has on *future* investment decisions.
- **It is not considered possible for the Proposal to produce both the More Efficient Generation Benefit and the SIMI Benefit to the extent that has been quantified**: It is not clear from Pioneer's submission on what basis it makes this statement, therefore it is difficult for us to comment explicitly, except to say that both benefits were modelled individually and separately. Therefore, when modelling the more efficient generation benefit, we did not assume that the SIMI charge would change, and when we modelled the SIMI benefit, we did not assume in that future AoB charges would apply to future transmission investments. As such, it is not clear why the modelling approach could produce both the More Efficient Generation Benefit and the SIMI Benefit.

21. Prudent Discount Policy

21.1. Summary of the issues on the PDP

The Authority has asked us to consider a number of issues raised by respondents related to the PDP. These include:

- The CBA was not a robust assessment of the value of the expanded PDP because… NZAS is presumably not the only customer of Transpower that will apply for a prudent discount… we do not agree that the profit it receives as a result of the discount would equal the efficiency benefit from the PDP, which is what the model seems to assume… Other transmission customers would suffer increased charges (PwC)
- PDP benefit ($10m): methodology highly sensitive to assumptions, therefore it is "artificial" and sensitive to exogenous factors, such as world aluminium prices
- That is a "hypothetical analysis"
- Efficiency equals profitability of customer with no evidence as to how that constitutes a net benefit. (Pioneer)
- Potential inefficiencies are not considered (Pioneer)
- That it ignored positive impact on wholesale market of a major load exiting (Pioneer)
- The EA should undertake further CBA on the potential reduction in wholesale prices that could occur if the PDP was not expanded and a business did close, and compare this with the potential increase in transmission charges in this scenario (Fonterra)

21.2. Response to the issues raised on the PDP

In relation to the general statement that the "*analysis is hypothetical*", it is self-evident that the analysis contained within any CBA may reflect hypotheses, simply by virtue of the fact that the CBA reflects modelling of a future *that differs to what has happened previously*. Therefore, to our mind, to deem that because a CBA reflects an "hypothesis" it doesn't pass the threshold test of "robustness", is inconsistent with the nature and purpose of a CBA, which is in fact to estimate future benefits and costs – many of which may not be supported by empirical evidence. To our mind, the more pertinent issue is whether the hypothesis (i.e., the proposed explanation that has been made on the basis of limited empirical evidence) is reasonable. To this end, we are comfortable that our working hypothesis – that the correct use of the PDP as it was original proposed would lower the probability of some customers inefficiently exiting the grid – is consistent with economic theory, and is practicable.

The above discussion then leads us into whether or not the CBA was a robust "*estimate of the value of the expanded PDP"* given that *"NZAS is presumably not the only customer of Transpower that will apply for a prudent discount…"* . We agree that other customers (not just NZAS) may be eligible to access the PDP in the future, however to suggest that because we only choose to model the largest, most likely affected customer, this renders the analysis "not robust", is, in our view, incorrect. Firstly, if implemented correctly, the further use of the PDP to other customers that meet the requisite characteristics of its use, only "improves" economic efficiency, therefore, analysing more customers simply increases the benefit that could be attributable to this component of the TPM. Therefore, if a criticism were to be levelled around 'only doing one customer', it would be that we have been too conservative when assessing the net benefits of this component of the TPM. However, to suggest that it is "not robust" ignores the fact that:

- Modelling more customers in addition to NZAS would only have increased the net benefit (i.e., the outcome is asymmetric), within an analysis that already indicated that the CBA results were positive under all cases (i.e., assessing more customers does not affect the "sign"); and
- Modelling more customers in additional to NZAS comes at a cost (time and effort), and like any project like this, there is a trade-off between the costs associated with undertaking a task (for example, estimating the benefits of the PDP to every single potentially eligible customer), and the (ever) declining benefits that come from undertaking that calculation for more marginal customers.

In short, these two broad criticisms do not dissuade us from the approach we adopted in the original CBA, nor any criticism that the analysis was "artificial" as it relied on assumptions around exogenous factors such as world aluminium prices. In relation to the latter, it is self-evident that numerous assumptions must be made to complete this aspect of the modelling, including the prices that a business may be able to sell their product for. In relation to the modelling we undertook specifically, we probability weighted the sales price outcomes – we didn't simply assume that the affected party would only sell its product at abnormally low prices for the entirety of the plant's useful life. The inference from the comment that no benefit should be ascribed to the PDP, simply because it requires an assumption to be made around such a factor, would imply that analysis could never be undertaken, because reliance on any assumption would render the modelling incorrect. This, to us, is an unrealistic threshold test.

There are three broad methodological issues raised by various parties in their submissions that the Authority has asked us to respond to. These are:

- *Although NZAS would benefit if it received a prudent discount payment, we do not agree that the profit it receives as a result of the discount would equal the efficiency benefit from the PDP, which is what the model seems to assume*[33].

  Firstly[34], to be clear, OGW assumed that "gross profit" reflects the producer surplus generated from the on-going operation of the business. Following on from this, we assumed that that if the PDP allowed a customer to generate gross profits (whilst paying at least their avoidable costs of supply for transmission services) when it otherwise wouldn't have in the absence of the PDP, then this would be an economic benefit.

  Secondly, PwC has provided no backing for this statement, for example, PwC has not stated '*why',* in economic terms, that it does *"not agree that the profit it receives as a result of the discount would equal the efficiency benefit from the PDP".* In the absence of any explanation, this is an unsubstantiated comment.

  Furthermore, and most importantly, after review, we remain of the view that gross profit, which is generally considered to reflect the difference between revenue and the marginal cost of making a product or providing a service, is a reasonable reflection of an individual business' producer surplus, which in turn is generally defined as the difference between the total income derived from the sale of a product and the costs involved in its production. For example, Pindyck and Rubenfield[35] state that "*producer surplus measures the total profits of producers, plus rents to factor inputs*", and together, "*consumer and producer surplus measure the welfare benefit of a competitive market*".

- *Other transmission customers would suffer increased charges if NZAS (or anyone else) receives a prudent discount. Assuming the Authority is correct that the proposed TPM would deliver cost-reflective and service-based pricing, the effect of applying an expanded PDP would be to make charges for other customers less service-based or cost-reflective. The costs of this should surely also be assessed within the CBA*[36].

  The statement that "*other transmission customers would suffer increased charges if NZAS (or anyone else) receives a prudent discount*" is only partially correct, as it depends on the counterfactual. In particular, it is important to note that the transmission bills of other customers will **increase** if a large customer such as NZAS disconnects from the network because that customer is now no longer contributing to the recovery of Transpower's approved revenue. Therefore, the originally proposed PDP, if it were applied correctly, would constrain the increase in costs and therefore benefits the remaining customer base, relative to if the PDP charge were not applied, and that caused that customer to inefficiently disconnect from Transpower's network.

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33 PWC, "*Submission to the Electricity Authority on Transmission Pricing Methodology Review: Second issues paper; and Distributed Generation Pricing Principles*" - PwC submission on behalf of a group of 14 EDBs, 26 July 2016, page 18

34 This statement is similar to an issue that the Authority has asked us to respond to in relation to Pioneer Energy's submission, namely: that: *Efficiency equals profitability of customer with no evidence as to how that constitutes a net benefit.* (Pioneer, p.20). As such, this response also applies to this issue that has been raised by Pioneer Energy.

3535 Pindyck and Rubinfield, "*Microeconomics*", Third Edition, page 278

36 This statement is similar to an issue that the Authority has asked us to respond to in relation to Pioneer Energy's submission, namely: that: 'Potential inefficiencies are not considered (Pioneer, p.20). As such, this response also applies to this issue that has been raised by Pioneer Energy.

However, it is correct to say that relative to charging levels that are in place just before the PDP is implemented, other transmission customers would see increased charges. In this context, we interpret PwC's statement as implying that this increase will lead to a reduction in economic efficiency ('*The costs of this should surely also be assessed within the CBA').* In this context, this statement implies that there is a zero sum game from adjusting price signals, that is, that it is impossible to re-structure prices to improve economic efficiency.

We do not agree. The structure of tariffs, and not just the overall level (i.e., the bill level), is fundamentally important to the achievement of economic efficiency, and while service-based and cost-reflectivity are important guides, from an economic perspective, we are primarily concerned with whether:

- the marginal price signal reflects forward-looking costs and thus incentivising (improved) economic decisions; and
- whether the recovery of residual costs including the cost of historical investments distorts future consumption or investment behaviour.

As we stated in our original report (and in this report), subject to two provisos, the way in which residual costs including *historical investments* are recovered – which is central to the PDP discount, as the recipient of the PDP should always be charged at least their avoidable cost of supply – should not materially influence economic efficiency.

As we note on page 23-24 of our original report, the two provisos to this are that the recovery mechanism minimises the extent to which it:

- distorts the future usage of the existing network (eg, consumption decisions); or
- leads customers (including generators and distributed generators) to make inefficient connection, disconnection or other investment decisions.

In this context, if the PDP discount provided to one customer is recovered from other customers in a way that does not breach those two provisos (i.e., it doesn't distort marginal price signals therefore customers' future usage of the network, or customers' future connection/disconnection decisions) then the fact that other customers' bills might increase as a result of the application of the PDP does not result in a loss in economic efficiency. The original TPM proposal, in our view, met this requirement, in particular, because the[37]:

- Approach to calculating the AoB charge for new (forward-looking) investments would not be compromised as a result of the recovery of the PDP discount; and
- The PDP itself mitigated the risk that other customers would inefficiently disconnect from the grid as a result of the reallocation of another customers' discount. The reason being that any "misallocation" of that discount (i.e., any allocation that may lead to another large customer making an inefficient disconnection decision) would, in theory, lead to another PDP application, and hence another reallocation. This process would continue until the recovery of residual costs is being undertaken in a way that does not lead to inefficient disconnection decisions. That said, our view is that this iterative recalculation process is improbable, given the magnitude of the discounts likely to be sought as compared to the number of end customers any reallocation could be smeared across.

37 Section 10 contains more information regarding this issue.

- *That it ignored positive impact on wholesale market of a major load exiting*[38]
  - In answering this question, we presume that the basis for the respondent's argument is that, everything else being equal, the market clearing price for electricity in the wholesale market should decline, as demand for energy reduces (with the loss of a major customer such as NZAS);
  - Assuming the above interpretation is correct, the implication in this statement is that economic efficiency could be improved by effectively "forcing" a customer to disconnect from the transmission network, by continuing to charge them a transmission price that exceeds their avoidable cost of supply. They would disconnect even though they would have been otherwise willing to pay at least Transpower's avoidable cost of supplying them to consume those transmission services. From an economic perspective, assuming the wholesale market is efficient (i.e., energy is being traded to its highest value use, and therefore, all energy consumers, including those subject to a PDP discount, are paying the economic cost of the energy that they are consuming), then any such forced disconnection would only reduce economic efficiency;
- Further to this, whilst it is true that the wholesale price is likely to decline as a customer is forced from the network (and therefore overall demand declines), this:
  - Increases consumer surplus, in that remaining customers get access to energy at a lower price, and some new customers get access to energy that they otherwise wouldn't have if the price had remained higher; *however*
  - Leads to an even larger reduction in producer surplus as existing producers receive a lower price for the energy that they sell, and some generators are now not dispatched.

In summary, the majority of the changes that would stem from an overall reduction in demand as a result of a PDP recipient <u>in</u>efficiently leaving the network, represent wealth transfers, not economic benefits, as the increase in consumer surplus is simply a transfer from producers. However, in our view, the loss in producer surplus is likely to exceed consumer surplus, diminishing economic efficiency[39].

22. More efficient quantity of services demanded benefit

22.1. Summary of the issues raised on the more efficient quantity of services demanded benefit

The Authority has asked us to consider an issue raised by respondents related to the 'more efficient quantity of services demanded' benefit. This was:

- *The significant difference between the marginal price for electricity and the marginal cost of supply is evidence that decreases in quantity demanded is likely to have negative welfare consequences overall. Oakley Greenwood's analysis examines only the benefits of lower quantity demanded, to the exclusion of significant categories of costs.* (Trustpower)

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38 This statement is similar to an issue that the Authority has asked us to respond to in relation to Fonterra's submission, namely: that: "*The EA should undertake further CBA on the potential reduction in wholesale prices that could occur if the PDP was not expanded and a business did close, and compare this with the potential increase in transmission charges in this scenario*". As such, this response also applies to this issue that has been raised by Pioneer Energy.

39 The magnitude of the loss will be dependent on the slope of the supply and demand curves.

22.2. Response to the issues raised on the more efficient quantity of services demanded benefit

Based on a number of respondent's comments, there appears to be some misunderstanding as to what we were trying to model in this section of the CBA. In summary, the rationale is that more cost-reflective transmission tariffs could potentially flow through to more efficient distribution (and subsequently retail) pricing structures, and hence, more efficient levels of consumption.

For example, a distribution business facing a future AoB charge for a future asset/s whose construction is driven by that distribution business' forecast growth in peak demand, may signal this future AoB charge in their own distribution pricing structures. For example, it may propose a *demand* charge that reflected:

- The forward looking costs of that AoB charge, and
- The time periods when its system was peaking, and hence, the demand that was causing the load growth on the part of the network being subjected to the charge.

This was the intention of our modelling in the CBA. In doing this, we:

- Assumed that future augmentation related transmission capital investments would be signalled to customers in the form of more cost-reflective retail tariffs (e.g., demand tariffs focused on the period in question) under the AoB proposal; however it
- Incorrectly assumed that all of the current transmission charges would be being passed through to retail charges in the form of a fixed charge.

As some respondents have pointed out, the current RCPD charge may in in fact be being passed through to retail customers as a variable charge. For example, Unison states[40]:

> *The above analysis does not make sense to Unison, particularly as the RCPD price signal in the current interconnection charge will be replaced by a more fixed and unavoidable residual charge based on capacity. Industrial customers in particular will have fewer incentives to avoid peak periods, so if anything, peak demands are likely to increase.*

Unison goes onto state that[41]:

> *If the AoB and residual charges become more difficult to avoid (e.g. based on capacity allocations as opposed to RCPD), fixed distribution and retail costs will likely increase not reduce, at least in the short-term*

We accept this error in our modelling assumptions. We also agree with the two comments from Unison that we have repeated above. However, if one assumes that the RCPD charge is being passed through to end customers, and that the rate exceeds the forward looking costs of providing transmission services (which is what we have modelled), then everything else being equal, inefficient consumption behaviour will be occurring if that RCPD charge is being reflected in end retail tariffs. The reason for this is simply because the marginal retail price would exceed the marginal cost of supply during the periods covered by the RCPD charge.

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40 Unison, *Submission on the Transmission Pricing Methodology: Second Issues Paper*, 26 July 2016, page 17

41 Unison, *Submission on the Transmission Pricing Methodology: Second Issues Paper*, 26 July 2016, page 17

So when Unison states that "*Industrial customers in particular will have fewer incentives to avoid peak periods, so if anything, peak demands are likely to increase*", this would actually be a more efficient outcome than the status quo, because it would be more reflective of the underlying costs of supply. Therefore, moving to more "*fixed distribution and retail costs*" for the recovery of the AoB (related to sunk assets) and the residual charge - as is postulated by Unison - will theoretically improve economic efficiency over and above what we have modelled in our CBA. We have not revised our modelling due to the likely materiality of the change.

23. Future investment in services that may be substitutes

23.1. Summary of the issues raised on the "future investment in services that may be substitutes" benefit

The Authority has asked us to consider a number of issues raised by respondents related to the "future investment in services that may be substitutes" benefit. This was:

- *does not demonstrate this could not be achieved under current TPM, and*
- *benefits from investment in substitutes should exist irrespective of the proposal. Removing the Demand Response Benefit and the Deferral Benefit from the CBA would reduce the benefits that have been quantified by OGW by $4m, from $213m to $209m…Demand response and deferral benefits are not specific to the proposal. (Pioneer)*

23.2. Response to the issues raised on the "future investment in services that may be substitutes" benefit

The respondent's line of reasoning appears to indicate that even in the absence of a price signal that reflects the forward-looking costs of supplying transmission services, for the purposes of developing the CBA, we should have assumed that the benefits from any investment in more efficient substitutes to a transmission investment would have existed irrespective of the proposal (i.e., that they will occur, not matter what the price signal is).

In our view, the starting point of any analysis of this kind is that price is the signal to participants in markets to either consume (or not consume) or invest (or not invest) – depending on their willingness to pay for the products being traded in that market. That is, participants will respond to these price signals in a way that maximises their own financial benefit, and markets will lead to prices varying as the supply and demand for goods and services varies, which in turn leads to efficient consumption and investment decisions being made by participants in that, or connected to, that market. This is a well-established principle in economics.

However, if there are other regulatory or institutional arrangements that seek to provide a second best solution to a market based solution, then this would obviously need to be considered. We note that the respondent has not outlined what the non-market based solution is that would facilitate efficient future investments in services that may be substitutes to a transmission investment in all cases, the costs incurred in implementing and continuing to maintain such a solution (which may be able to be avoided if a market based solution were adopted), the effectiveness of that solution, or why it is of the belief that conventional economic theory should not form the basis of the evaluation of these potential alternative solutions.

24. General comments

24.1. Summary of the general issues raised

The Authority has asked us to consider a number of general issues raised by respondents related to the CBA. These were:

- The OGW analysis…simply assesses that use of volumetric charges would result in deferral of transmission investment and treats this as a benefit – basically, under the OGW analysis the higher the variable distribution prices are the better. (Powerco)
- Oakley Greenwood adopt a conceptual approach which varies from the decision-making and economic framework developed by the Authority. This conceptual framework is presented largely without reference to supporting literature, and without an attempt to reconcile the approach to the Authority's DME or its problem definition (NZAS)…
- CBA should focus on marginal impacts attributable to the decision being considered and examine uncertainties (Genesis, Castalia)
- The Authority should have modelled its preferred charge under a range of scenarios based on reasonable assumptions in the knowledge that Transpower will have their responsibility to decide actual design parameters (Trustpower)
- No top down CBA has been produced (Trustpower)… No cross check by reference to top-down estimates and no empirical evidence of benefits
- Not assessed the impact of the proposed reforms on final customer prices, and has not applied the CBA Working Paper's process for estimating the distribution of benefits and costs of each option
- CBA complex (Trustpower)

24.2. Reponses to general comments

Before addressing the specific comments, it is useful to revisit two we have made throughout these responses. The first is that a CBA assesses whether a particular proposal leads to net economic benefit (economic benefits outweigh costs). A CBA does not involve the creation of the proposal. The second point is that economic benefit from the introduction of a pricing regime is the difference in benefit arising from the decisions of the parties exposed to the prices compared to the decisions they would make if the proposal was not implemented.

Turing to the particular comments:

- **Under the OGW analysis the higher the variable distribution prices are the better:** This is not correct. Our position is that the more *cost reflective* prices are, the better from an efficiency perspective (excluding administrative / implementation costs). Our modelling was designed to assess the impact of passing through the AoB charge (as it related to *future* demand driven transmission investments) on the quantity of energy that end customers consume at times of system peak demand. This in turn would lead to lower overall costs of supply.

- **Oakley Greenwood adopt a conceptual approach which varies from the decision-making and economic framework developed by the Authority**: It is not clear from the statement, why the respondent considers our approach to vary from the decision-making and economic framework developed by the Authority. The Authority has never advised us that they consider this to be the case. Notwithstanding this, the economic framework establishes a hierarchy of charging approaches and then the elaboration focuses on the importance of charges being service-based and cost-reflective. To our mind, the approach in the CBA attempts to reflect the level of cost-reflectiveness of the proposal. For example, it explicitly seeks to assess whether the AoB charge in combination with the marginal cost adjustment, for future demand driven expenditure, sends a more cost-reflective price signal than the existing TPM. It assesses whether the proposed arrangements for recovering residual (i.e., either through an AoB approach or through the residual charge approach) will likely avoid distorting future consumption or investment behaviour. Finally, we noted that theoretically, the recovery of residual costs which included historical investments in existing assets could impact upon future investment and consumption decisions, for example, if it led to charges exceeding a customers' willingness to pay for transmission services. We modelled this as part of our assessment of the PDP arrangements.
- **CBA should focus on marginal impacts attributable to the decision being considered and examine uncertainties (Genesis, Castalia):** The issue around examining uncertainties has been addressed in section 18 of this report. Regarding the comment that the CBA should focus on marginal impacts, it is not entirely clear to us what the basis of this comment is, as intentions of the CBA was to focus on the marginal impacts. For example, it explicitly sought to assess whether the marginal price signals that are sent in relation to future demand driven expenditure (e.g., the AoB charge, in combination with the marginal cost adjustment) are more cost-reflective than the existing TPM. In our CBA, we have explained why we have only focused on demand-driven investment, and ignored the marginal price signals that pertain to other types of investment, including replacement, safety-related and corporate investments.
- **The Authority should have modelled its preferred charge under a range of scenarios based on reasonable assumptions in the knowledge that Transpower will have their responsibility to decide actual design parameters**: Firstly, the CBA is in theory, for a change in the Guidelines, and not for a specific change in the methodology. That said, to undertake any quantification of the impact of the changed Guidelines, it is necessary to "work back" to determine what this might mean for changes in prices/structures. This is effectively what we have done for the purposes of modelling in the CBA, although this should not take away from the principle that it is the Guidelines that are changing and which are effectively at issue. Regarding the statement that the preferred charge should have been modelled under a range of scenarios based on reasonable assumptions, we would point the submitter to the sensitivity tests we undertook and reported in the original CBA. We think these reasonably represent the factors that might influence the benefits and costs of the outturn proposal, as implemented under the Guidelines.

- **Top down:** We did not produce a top down CBA, rather, a detailed bottom-up CBA, with sensitivity analysis undertaken to inform the likely CBA results under a range of feasible outcomes. In our opinion, any top down CBA is likely to result in an unreliable outcome, as the actual benefits and costs of any proposed change in pricing arrangements must reflect the particular characteristics of the proposed changes, given the market that they are being applied to. Also a top down approach is inevitably less transparent. If we were to develop a top down CBA to complement the bottom up CBA we have produced it is hard to see that differences would not need to be resolved in favour of the bottom up approach given the high level assumptions that would of necessity be needed for a top down approach. In respect of empirical evidence, we do not understand this point in that empirical evidence of the future is a logical contradiction. We do not think it necessary to provide evidence investors responding to price signals – many of the submissions state this is reality.
- **Not assessed the impact of the proposed reforms on final customer prices, or the distribution of benefits and costs of each option:** Correct. In saying this, the Authority has not asked us to complete either of these tasks, however it is our understanding that at least the former has been modelled by other parties assisting the Authority.
- **CBA is complex:** Yes, it is, however the alternative is to adopt a high level approach that uses very generalised assumptions and is less transparent, which suffers what we believe to be even larger drawbacks.

Appendix A – Extract from "[ ]"