Economic Review of Transmission Pricing Supplementary Consultation Paper

A Report for Transpower

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Abbreviations

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AIC	Average Incremental Cost
ATC	Average Total Cost
Authority	Electricity Authority
Axiom	Axiom Economics
CBA	Cost-benefit Analysis
Commission	Commerce Commission
EA	Electricity Authority
EDB	Electricity Distribution Business
LNI	Lower North Island
LRMC	Long Run Marginal Cost
LSI	Lower South Island
MBAM	Marginal Benefit Adjustment Mechanism
NPV	Net Present Value
OGW	Oakley Greenwood
OGW CBA	Oakley Greenwood Cost-benefit Analysis
RCPD	Regional Coincident Peak Demand
SRMC	Short Run Marginal Cost
TPM	Transmission Pricing Methodology
UNI	Upper North Island
USI	Upper South Island

Executive Summary

This report has been prepared by Axiom Economics (Axiom), on behalf of Transpower. Its purpose is to evaluate the Electricity Authority's (Authority's) Supplementary Consultation Paper (Consultation Paper)[1] on the Transmission Pricing Methodology (TPM). Our report[2] in response to the Second Issues Paper[3] highlighted several problems with the proposals contained within it. Most notably, we concluded that:

We reached three key conclusions in our previous report.

- the combination of nodal prices and the 'shadow prices' associated with the proposed 'area of benefit' (AoB) charge would not provide customers with an efficient *ex-ante* price signal of Transpower's future investment costs, and an *explicit ex-ante* price signal of some kind was required, such as an LRMC charge;
- there was no reason to be confident that allocating the costs of investments after they had been sunk via an AoB charge would promote static efficiency or be more equitable overall, yet there was good reason to expect the proposal would result in more disputes and much higher administrative costs; and
- the accompanying cost-benefit analysis (CBA) undertaken by Oakley Greenwood (OGW)[4] was not fit for its intended purpose, did not provide a robust indication of the likely impacts of the proposal and so could not reasonably be relied upon to support the methodology.

In its Consultation Paper, the Authority has proposed various changes to the methodology contained in its Second Issues Paper. OGW has also released two reports[5] in which it responds to some (but not all) of the criticisms directed at its CBA – including our own. Transpower has asked us to review the material set out in these new documents and to consider whether it causes us to change any of our key conclusions. In short, it does not, for the reasons we set out below.

What is LRMC pricing?

Our previous report explained the important differences between the *explicit* price signals that would be provided by LRMC charges (or modified versions of the RCPD and HVDC charges) and the *shadow* price signals that would be supplied by AoB charges. We explained why we thought that the latter would be a poor

1 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper, Supplementary consultation,* 13 December 2016 (hereafter: 'Consultation Paper').

2 Axiom Economics, *Economic Review of Second Transmission Pricing Methodology Issues Paper, A Report for Transpower,* July 2016 (hereafter: 'Axiom July 2016 Report').

3 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper,* 17 May 2016 (hereafter: 'Second Issues Paper').

4 Oakley Greenwood, *Cost Benefit Analysis of Transmission Pricing Options, prepared for: NZ Electricity Authority,* 11 May 2016 (hereafter: 'OGW CBA').

5 Oakley Greenwood, *Response to issues raised on CBA, prepared for: Electricity Authority,* 2 December 2016 (hereafter: 'OGW Response to Issues'); and Oakley Greenwood, *Impact of the proposed changes to the TPM on the CBA*, 9 December 2016 (hereafter: 'OGW Impact of Changes').

substitute for the former, and could result in inefficient operational and investment decisions.

Unfortunately, there has been a surprising degree of inconsistency across the various consultation documents regarding the basic economic principles underpinning LRMC pricing, and the various forms that it might take in practice. For example, in a significant departure from the orthodox position taken in its previous LRMC Working Paper,[6] in which the Authority noted that "LRMC is forward looking, as it is the cost of future changes in capacity of the grid to meet future changes in demand", it now states that it sees an LRMC charge:[7]

> *'…not as a forward looking price for future investment (even if it is calculated on the basis of the cost of future investment) but as a price that reflects the opportunity cost of the current use of a scarce resource – the existing grid. The user who benefits from the grid pays the LRMC charge not because future investment is required but because the opportunity cost of their use of the existing grid is the cost of denying another user the use of the existing grid.'*

The Consultation Paper adopts an unorthodox definition of LRMC and takes an overly narrow view of how such a price might work in practice.

It is unclear why the Authority no longer views an LRMC charge as a forward-looking price for future investment. In our opinion, that is the accepted, uncontroversial definition of LRMC pricing in economics. It is also not obvious whether that change has material consequences or is merely semantic. In any event, in our opinion, the accepted definition of LRMC pricing is inconsistent with the view expressed in the Consultation Paper: put simply, an LRMC price is designed to signal the *future costs* that would be incurred from using more energy.

In a similar vein, the Authority has taken an unduly narrow view of how an LRMC price would be put into practice. It appears to think that the prices would be highly volatile and applied either to very narrow geographic areas or to individual investments. All the supposed problems it identifies with LRMC charges can be traced back to these key assumptions as to the basic design elements. Yet there is no need for an LRMC charge to take this form. It could easily be applied to broader geographic areas and/or designed to provide a more stable price signal over time. For example, OGW's CBA assumes a simple four region LRMC pricing regime.

Much of the analysis of LRMC pricing set out in the Consultation Paper consequently rests on: a) a misunderstanding of the underlying economic principles; and/or b) any unduly narrow perspective of what an LRMC charge might look like, in practice. For the avoidance of doubt, throughout the remainder of this report, we adopt the economically orthodox definition of LRMC, consistent with the LRMC Working Paper, and countenance practical applications of that concept that extend beyond the narrow formulation assumed in the Consultation Paper (and in the Second Issues Paper).

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6 Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.iii (hereafter: 'LRMC Working Paper').

7 Consultation Paper, p.35.

Would there be efficient forward-looking price signals?

In our previous report, we concluded that the proposed methodology would not provide efficient forward-looking price signals.

In our previous report, we concluded that the proposed suite of reforms – most notably the replacement of the RCPD and HVDC charges with an AoB charge – would not provide customers with efficient forward-looking price signals of future costs before investments were made to elicit desirable changes in behaviour. Most notably, we explained why:

- the explicit *ex-ante* price signals provided by nodal prices and losses would not provide sufficient signals to grid users of the costs that Transpower will incur in the long-run when it replaces or upgrades its assets; and
- the implicit *ex-ante* 'shadow price' signal provided by the AoB charge would not provide a predictable, accurate signal of Transpower's long-run costs to which grid users could respond – even if they were inclined to do so.

We concluded that for grid users to face an efficient signal of the potential future costs of investments in the interconnected grid, there must be an *explicit ex-ante* price signal. We stated that such a charge might be a varians of the existing RCPD and HVDC charges, or a new LRMC-based charge. In its Consultation Paper, these recommendations are dismissed for three key reasons; namely:[8]

- nodal prices are said to be sufficient to elicit efficient short- and long-run operational and investment decisions, obviating the need for an additional *ex-ante* price signal such as an LRMC charge;
- AoB charges are said to be able to provide a more efficient price signal than LRMC charges, and it is claimed that grid support payments could also be relied upon to defer the need for future grid investment if required; and
- Transpower has the option of introducing an LRMC charge if it wishes, i.e., if it has exhausted all other options – the AoB charge and grid support payments – but still feels that an additional signal is needed.

Nodal prices alone may not be sufficient to elicit efficient long-run outcomes.

The assertion in the Consultation Paper that nodal prices can be relied upon to provide efficient short-run price signals *and* to provide efficient *long-run* signals is puzzling. It is inconsistent with both economic theory and the Authority's previous positions. Indeed, the LRMC Working Paper concluded that:[9]

> *'…, nodal pricing is likely to result in price signals systematically below LRMC … nodal prices are likely to under-signal LRMC so LRMC charges could potentially promote more efficient investment. However, while LRMC charges may be appropriate, nodal pricing will still provide some signal of marginal cost, albeit muted.'*

The contention is also very difficult to reconcile with the remainder of the proposal. If nodal prices really are sufficient to elicit efficient outcomes, then why would there be any need for the AoB charge or grid support contracts to provide further price signals? The Consultation Paper plainly envisages the AoB charge and bespoke

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8 Consultation Paper, p.xiii.

9 Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.29.

contracts for grid support playing an important signalling role yet, if the Authority's categorical statements about nodal prices were correct then, presumably, no such signals are needed. Indeed, they would do more harm than good.

In our opinion, for precisely the reasons cited by the Authority in its earlier LRMC Working Paper, nodal prices *cannot* be relied upon to deliver efficient long-term pricing signals of future investment costs. There is therefore a potential role for the TPM to play in 'plugging this gap', as it were. There is also a wide variety of ways in which an LRMC charge might assist in that respect, depending upon the way it is designed and implemented.

The AoB charge would not provide an efficient ex-ante price signal.

There is similarly nothing in the Consultation Paper that causes us to change our opinion that the four key conditions for efficient shadow pricing do not hold for the proposed AoB charge. The paper does not identify any other legitimate advantages that AoB charges would have over LRMC prices – the comparisons made in this respect are not valid. The paper also does not address the potential inefficiencies that may arise from levying AoB charges on generators, such as:

- the proposal to allocate AoB charges to generators based on their average injections when calculating bespoke private benefits is not practicable could cause generators to factor those transmission costs into their offer prices, thereby compromising the efficiency of the wholesale market;
- depending upon how AoB charges are assigned to new entrant generators (a matter upon which the Draft Guidelines provide no real instruction) this might affect the size and/or nature of the plant that is installed, e.g., a generator might decide to install a smaller plant to avoid paying a higher AoB charge;
- levying an additional fixed charge on generators would also increase the average expected wholesale electricity price required to make new generation investments commercially viable,[10] resulting in higher future wholesale prices than would otherwise have been the case;[11] and
- under the 'base proposal', the AoB charge would provide the counterintuitive signal to generators (and load customers, although they are less likely to respond to it) that it is 'cheaper' for them to invest in areas supplied predominantly by assets built before 2004.[12]

Furthermore, in our view, bespoke grid support payments cannot serve as an effective *primary* vehicle for eliciting network support. Such arrangements are only

10 Specifically, it would increase a new generator's 'break-even' points, i.e., it would render a generator that was only marginally profitable under the existing TPM, unprofitable. Wholesale electricity prices would therefore have to increase to cover existing generators' higher costs. This is consistent with what one would expect to observe in any competitive market when input prices increase, i.e., those higher costs are passed-through to some degree.

11 It may serve to delay the point at which new generation plant comes online – or change the 'build order'. This would not be problematic if those decisions were being made in response to an efficient, cost-reflective price signal of long-run transmission costs. However, for the reasons set out above, the AoB charge would not provide such a signal. *See:* Axiom July 2016 Report, pp.27-28.

12 Although we note that Transpower would have the option of broadening the application of the AoB charge to encompass more historical investments.

possible when a mutually beneficial contracting opportunity exists that Transpower wishes to pursue. Those conditions would not always hold, in practice. Such contracts should therefore play an ancillary role to an explicit *ex-ante* price signal, such as an LRMC charge.

It is not enough for an LRMC charge to simply be an option.

Finally, the fact that Transpower would retain the option of introducing an LRMC charge under the proposed guideline does not mean that it would be inclined to do so; particularly given the significant negative commentary on such charges in the Consultation Paper. And nor does it mean that efficient operational and investment outcomes would arise in the absence of such charges.

Table ES.1 provides a comprehensive summary of all the points that we raised in relation to the price signals provided by the proposed methodology in our previous report, and whether they have been considered and addressed satisfactorily.

Table ES.1: Would there be an efficient forward-looking price signal?

Issues raised in previous report		Outcome
Sufficiency of nodal price signals.	Nodal prices would not adequately signal Transpower's forward-looking costs, and so an additional *explicit ex-ante* price signal is needed to plug that gap, e.g., an LRMC charge or a modified version of the RCPD charge.	Considered but unresolved
The AoB charge would not provide an efficient 'shadow-price' signal that would effectively 'plug the gap' between nodal prices and LRMC	Customers would be unlikely to draw a direct link between their own actions and the implications for Transpower's future costs	Considered but unresolved
	Customers would be unlikely to accurately predict the AoB charges that they would fact in the future if they respond in certain ways.	Considered but unresolved
	The shadow prices that customers would face would not reflect the 'gap' between the LRMC of future investment costs and nodal prices.	Not considered[13]
	Customers may not respond to the shadow price signals, because any benefits they derive could depend on the actions of others, resulting in 'tragedies of the commons'.	Considered but unresolved
	The proposed marginal benefit adjustment mechanism (MBAM) would not address the problems listed above and would create other significant problems.	Considered and partly resolved[14]
Application of AoB charges to generators.	The AoB methodology could give rise to inefficient consumption and investment decisions by generators.	Unresolved

13 The Consultation Paper does touch fleetingly upon the divergence between AoB charges and LRMC prices in its evaluation of OGW's CBA. However, it comprises a single declarative statement with no accompanying analysis. *See:* Consultation Paper, Appendix D, p.3.

14 The proposal to relegate the mechanism to an optional component of the methodology is welcome, but it does not address the broader problems surrounding the inefficiency of the price signals.

The proposed approach would not provide efficient ex-ante price signals.

For these reasons, the material set out in the Consultation Paper has not caused us to alter our conclusion that the proposed TPM changes – and the AoB charge in particular – could not be relied upon to provide efficient signals to customers of future costs before investments are made to elicit desirable changes in behaviour.

Would there be a more efficient allocation of sunk costs?

In our previous report, we concluded that the proposed approach may not produce a more efficient allocation of sunk investment costs.

Our previous report also considered whether the proposed charging methodology might result in a more efficient allocation of sunk costs *after* investments had been made. We observed that:

- changing the way in which sunk costs are allocated by implementing an AoB charging methodology may not improve allocative efficiency;
- the AoB charging approach would be likely to give rise to significant additional costs, i.e., reduce productive inefficiency; and
- the proposed residual charge on load could give rise to distortions and be considered unfair.

We consequently concluded that the proposal may not result in a more efficient or fairer allocation of sunk investment costs. Having reviewed the material in the Consultation Paper, including the proposed changes to the methodology, we remain of the view that the AoB charge may not improve allocative efficiency relative to alternative approaches, since:

The proposal may not improve allocative efficiency.

- while any inefficient load shedding would cease in the near-term if the proposal was implemented, this would be due simply to the removal of the RCPD charge, not the introduction of the AoB charge, e.g., an LRMC charge could do the same;
- there *were* allocative inefficiencies arising from the HAMI-based parameter on the HVDC charge, but these have diminished significantly following the announcement of the SIMI-based parameter;
- imposing a substantial amount of additional transmission charges on final load customers would be likely to result in a reduction in demand, which would give rise to an allocative efficiency loss; and
- any allocation of AoB charges to generators that is based on their average injections has the potential to distort their bidding conduct, compromising the efficiency of the wholesale dispatch process.

The proposal would give rise to significant productive inefficiency.

We also consider that the revised proposal would give rise to significant productive inefficiency from:

- the additional costs that would be incurred estimating private benefits and giving effect to the AoB charging methodology more generally; and
- the extra costs that would accompany the increase in lobbying and disputation that would be expected to follow the introduction of an AoB charge.

We also continue to believe that the proposed residual charge on load could give rise to distortions and might, in some circumstances, be considered unfair, since:

The residual charge may result in distortions and be seen as unfair.

- there would still be some risk of customers inefficiently changing their conduct – particularly as the time approaches for the residual charge to be 'reset'; and
- the significant wealth redistributions that would occur under the proposal might be viewed by some customers as inequitable and a form of 'hold-up'.

Finally, it is not altogether clear to us that Transpower would be able to feasibly implement various aspects of the Draft Guidelines. For example, it is directed to strike an appropriate balance between 'accuracy and simplicity' when applying AoB charges yet, for the reasons we have explained, the methodology itself arguably *cannot* be accurate, since it would not be cost-reflective. The clauses requiring Transpower to correct for 'anomalies' and levy 'broadly equivalent charges' on businesses in 'broadly equivalent circumstances' are also unhelpfully vague and it is far from clear whether they could be implemented effectively.

Table ES.2 provides a complete summary of all the points that we raised on the extent to which the proposed methodology would result in a more efficient allocation of sunk costs in our previous report, and whether they have been considered and addressed satisfactorily.

Table ES.2: Would there be a more efficient allocation of sunk costs?

Issues raised in previous report		Outcome
Changing the way in which sunk costs are allocated by implementing an AoB charging methodology may not improve allocative efficiency.	While any inefficient load shedding would cease in the near-term if the proposal was implemented, this would be due simply to the removal of the RCPD charge, not the introduction of the AoB charge.	Considered but unresolved
	There were allocative inefficiencies arising from the HAMI-based parameter on the HVDC charge, but these have diminished significantly following the announcement of the SIMI-based parameter.	Not considered
	Imposing a substantial amount of additional transmission charges on final load customers would be likely to result in a reduction in demand, which would give rise to an allocative efficiency loss.	Not considered[15]
	Levying AoB charges on generators may compromise the efficiency of the wholesale dispatch process.	Unresolved
	The earlier proposal to apply depreciated historical cost (DHC) charges to existing assets earmarked for AoB charges was unnecessary and would have resulted in an inefficient time profile of prices.	Resolved

[15] Note that this point is considered by OGW in its report. However, as we explain below, its response does not address satisfactorily the underlying concern.

<table>
<tr><th colspan="2">Issues raised in previous report</th><th>Outcome</th></tr>
<tr><td rowspan="3">The AoB charging approach would be likely to give rise to significant additional costs, i.e., reduce productive inefficiency.</td><td>Additional costs would be incurred estimating private benefits, relative to the status quo.</td><td>Considered but unresolved[16]</td></tr>
<tr><td>Additional costs would be associated with the increase in lobbying and disputation that would inevitably follow the introduction of such a charge.</td><td>Not considered[17]</td></tr>
<tr><td>There would be ongoing disruptions associated with the application of the MBAM, applications for prudent discounts, and so on.</td><td>Considered and partly resolved[18]</td></tr>
<tr><td rowspan="3">The proposed residual charge on load could give rise to distortions and be considered unfair.</td><td>There would still be some risk of customers inefficiently changing their conduct – particularly in the lead ups to the residual charge being ‘reset’.</td><td>Not considered</td></tr>
<tr><td>The significant wealth redistributions that would occur under the proposal might be viewed by some customers as inequitable and a form of ‘hold-up’.</td><td>Considered and partly resolved[19]</td></tr>
<tr><td>It seemed neither necessary nor desirable to limit the potential residual charge allocation options that Transpower has as its disposal in the Guideline</td><td>Considered and partly resolved[20]</td></tr>
</table>

The proposal may not produce a more efficient (or fairer) sunk cost allocation.

The overall conclusion that we reached in our previous report consequently remains the same. Namely, while the revised proposal includes some welcome changes, we remain of the opinion that the methodology still would not result in a more efficient (or fairer) allocation of sunk investment costs.

Oakley Greenwood cost-benefit analysis

Oakley Greenwood undertook a cost benefit analysis (the ‘OGW CBA’), which estimated that introducing the AoB charge proposed in the Second Issues Paper would yield a net benefit of $213.3m in present value terms. In our previous report, we observed that the OGW CBA rested upon three foundational assumptions that did not hold; namely:[21]

16 The changes do not address the basic problem that Transpower would face estimating private benefits over the 30- to 50-year (or thereabouts) lives of interconnection assets. There would also be no way for Transpower to efficiently ‘trade-off’ between ‘accuracy and simplicity’ when setting AoB charge since, for the reasons we have explained, the charge is not cost-reflective.

17 Note is considered by OGW in its report, but its response again does not assuage the problem.

18 The paper proposes not to extend the prudent discount policy to encompass the exit of load and to relegate the MBAM to an optional component of the methodology – both beneficial changes.

19 The Guideline provides some (albeit rather unclear) direction to Transpower to avoid ‘charging anomalies’ and to levy residual charges that “result in broadly equivalent charges to customers that are in broadly equivalent circumstances”. There is also a transition mechanism but, as we explain in Appendix A, there are problems with its specification in the current Draft Guidelines.

20 We note that Transpower’s discretion is not unfettered in this regard. For example, clause 32(a) states that the method for calculating the residual charge must ‘use load to identify the designated transmission customers that must pay the residual charge, and the extent to which those customers must pay.’

21 Axiom July 2016 Report, p.53.

In our previous report, we observed that the OGW CBA rested upon three foundational assumptions that did not hold.

- that the AoB charge would provide an efficient *ex-ante* shadow price signal, when, for the reasons set out above, it would not, and would instead risk compromising static and dynamic efficiency;
- that the reallocation of costs – and resultant wealth transfers – that would occur under the proposal would not give rise to any allocative efficiency loss through inefficient reductions in demand, when that is not realistic; and
- that the AoB charges that each customer would pay can be proxied by an estimate of the LRMC of transmission in each RCPD region, when they would instead each face a unique price that may be above or below that level.

We explained also why many of the other more specific elements of the modelling did not reflect the way the electricity system functions or how its participants make decisions.[22] We concluded that no weight could be placed on the resulting estimate of net benefits. OGW's new reports do not assuage those concerns. Rather, for the most part, they simply confirm the existence of the problems that we identified. For example, OGW acknowledges that:

OGW acknowledges that there are shortcomings with its modelling.

- it has not modelled an AoB charge, but has instead modelled a charge where market participants would face a price equal to an estimate of the LRMC of transmission in each RCPD region – an entirely different approach;
- its modelling of generator entry does not reflect the way in which those decisions are made in practice, i.e., they are not based solely on the average total cost (ATC) of a unit of generation; and
- no adjustment was made in the modelling to account for the intermittency of wind generation, i.e., the assumption is made that wind farms can be relied upon during peak demand to operate at 100 per cent capacity.

Although OGW concedes that these are indeed features of its modelling, it suggests that the problems are immaterial. We disagree; particularly with the proposition that a regional LRMC charge forms a reasonable proxy for an AoB charge (for the reasons we set out above). We also do not accept the other contentions that OGW makes in defence of its methodology, including that:

OGW's claims that those shortcomings do not matter are not reasonable.

- EDBs would be likely to pass-through any increases in transmission charges entirely in the form of fixed distribution charges, resulting in no reduction in demand, when this would require an implausible series of assumptions to hold;
- it is reasonable to anticipate that the amount of embedded diesel generation would increase to 500MW if the status quo was retained, when no evidence has been provided to support this proposition; and
- there is no reason to think that the proposal would entail any significant increase in the level of dispute or administrative costs relative to the status quo, when there is good reason to expect that both these things would happen.

22 *op cit.*, pp.54-60.

Several other problems that we identified with the CBA that have the potential to compromise the results and render it unfit for its intended purpose are not considered at all. The two most significant omissions are the following:

- in calculating the benefits of deterring investment in inefficient alternatives to networks, the model assigns 100% weight to the 'Huntly Stays' scenario – this appears to simply be a mistake, and inflates the benefits estimate by $85m;[23] and
- OGW does not deal appropriately with 'end values', which causes it to make an arbitrary adjustment to the assessment of the HVDC charge (measuring it over 30-years instead of 20-years), inflating the benefits estimate by $115m;[24]

Several other very serious problems are not considered at all.

Simply addressing these two apparent inconsistencies within OGW's modelling using its own methodology – and leaving everything else unchanged – would reduce the estimated net benefit from $203m to less than $3m – or **by 99%**. To be clear, we are not suggesting that this would be the appropriate approach since, as we noted above, this striking result is largely symptomatic of deeper problems with the modelling.[25] Nevertheless, it is surprising that these points have not prompted at least some form of response, given their gravity.

Other significant problems that we raised in our previous report, but which were not addressed in any way include the following:

- the modelling does not account for the constraints associated with hydro-electric plants (e.g., annual inflows, energy storage constraints, etc.), which clearly are highly relevant considerations in a hydro-dominated system;
- the modelling assumes that a robust 'combined' LRMC can be obtained by adding an estimate of the LRMC of transmission (in $/MWh) to the ATC of generation (in $/MWh), which is not the case; and
- the calculation of benefits assumes that each plant generates as per its assumed capacity factor, i.e., once a generator has been constructed, it is presumed to have a fixed future level of output and costs, regardless of energy demand.

Table ES.3 provides a comprehensive summary of all the points that we raised in relation to the OGW CBA in our previous report, and whether they have been considered and addressed satisfactorily.

23 HoustonKemp, *Review of the cost benefit analysis of the proposed TPM guidelines, A report for Trustpower*, 26 July 2016, p.56.

24 *op.cit*, p.63.

25 Including, for example, the failure to properly employ terminal values to deal with the problems arising from lumpy cashflows described above.

Table ES.3: Oakley Greenwood cost-benefit analysis

Issues raised in previous report		Outcome
Foundational assumptions	The CBA assumes that the AoB charge would provide an efficient *ex-ante* shadow price signal, when, for the reasons set out above, it would not, and would instead risk compromising static and dynamic efficiency.	Considered but unresolved
	The modelling presumes that the reallocation of costs – and resultant wealth transfers – that would occur under the proposal would not give rise to any allocative efficiency loss through inefficient reductions in demand, when that is simply not realistic.	Considered but unresolved
	The CBA assumes that the AoB charges that each market participant would pay can be proxied by an estimate of the LRMC of transmission in each RCPD region, when each customer would instead face a unique price that may be above or below LRMC.	Considered but unresolved
More specific assumptions and modelling elements	In calculating the benefits of deterring investment in inefficient alternatives to networks, the model assigns 100% weight to the 'Huntly Stay's scenario – this appears to simply be a mistake, and inflates the benefits estimate by $85m.	Not considered
	The modelling does not deal appropriately with 'end values', which causes OGW to make an arbitrary adjustment to its assessment of the SIMI charge (measuring it over 30-years instead of 20-years), inflating the benefits estimate by $115m.	Not considered
	The CBA assumes that new generation entry decisions would be based solely on the average total cost of a new unit of generation.	Considered but unresolved
	The modelling presumes that new investments are determined only by maximum demand, and that capacity factors are fixed for all such investments, which is not realistic.	Not considered
	The CBA assumes incorrectly that wind farms can be relied upon to operate at a 100% capacity factor during peak periods.	Considered but unresolved
	The CBA does not take into consideration any of the constraints related to hydro plants, e.g., annual inflows, etc.	Not considered
	The modelling assumes incorrectly that a robust 'combined' LRMC can be obtained by adding an estimate of the regional LRMC of transmission (in $/MWh) to the ATC of generation (in $/MWh).	Not considered
	The CBA assumes there would be an implausible increase in embedded diesel generation (to 500MW) if the status quo is retained.	Considered but unresolved
	The modelling assumes that there would be no significant increase in administrative costs if the proposal was implemented.	Considered but unresolved

No weight can reasonably be placed on the OGW CBA.

It is consequently clear that the CBA modelling does not reflect accurately the proposed AoB charge methodology (including its inefficiencies), the way in which the electricity system functions or the way its participants make decisions. We therefore remain of the opinion that no weight can reasonably be placed on the resulting estimate of net benefits.

Conclusion

We have been asked to consider whether the material set out in the Consultation Paper and the accompanying documents causes us to change any of the key conclusions we reached in our previous report in response to the Second Issues Paper. It does not. We remain of the opinion that:

The Consultation Paper and accompanying documents have not caused us to change any of our previous conclusions.

- the combination of nodal prices, AoB charges and grid support contracts would not provide customers with an efficient *ex-ante* price signal of Transpower's future investment costs, and an *explicit ex-ante* price signal of some kind is required to elicit efficient outcomes, such as an LRMC charge;
- there is no reason to be confident that allocating the costs of investments after they have been sunk via an AoB charge would promote static efficiency or be more equitable overall, yet there is good reason to expect the proposal would result in more disputes and higher administrative costs; and
- the OGW CBA is not fit for its intended purpose, does not provide a robust indication of the likely impacts of the proposal and so cannot reasonably be relied upon to support the methodology.

We consequently continue to hold the view that the proposed methodology does not represent a clear improvement upon either the status quo, or alternative approaches in which LRMC charges are a core component, and not just a discretionary 'additional component'. It could instead reduce efficiency, overall.

1. Introduction

This report has been prepared by Axiom Economics (Axiom), on behalf of Transpower. Its purpose is to evaluate the Electricity Authority's (Authority's) Supplementary Consultation Paper (Consultation Paper)[26] on the Transmission Pricing Methodology (TPM). Our report[27] in response to the Second Issues Paper[28] highlighted several problems with the proposals contained within it. Most notably, we concluded that:

- the combination of nodal prices and the 'shadow prices' associated with the proposed 'area of benefit' (AoB) charge would not provide customers with an efficient *ex-ante* price signal of Transpower's future investment costs, and an *explicit ex-ante* price signal of some kind was required, such as an LRMC charge;

We reached three key conclusions in our previous report.

- there was no reason to be confident that allocating the costs of investments after they had been sunk via an AoB charge would promote static efficiency or be more equitable overall, yet there was good reason to expect the proposal would result in more disputes and much higher administrative costs; and
- the accompanying cost-benefit analysis (CBA) undertaken by Oakley Greenwood (OGW)[29] was not fit for its intended purpose, did not provide a robust indication of the likely impacts of the proposal and so could not reasonably be relied upon to support the methodology.

In its Consultation Paper, the Authority has proposed various changes to the methodology contained in its Second Issues Paper. OGW has also released two reports[30] in which it responds to some (but not all) of the criticisms directed at its CBA – including our own. Transpower has asked us to review the material set out in these new documents and to consider whether it causes us to change any of our key conclusions. We do so in the remainder of this report, which is structured as follows:

- in **section two**, we seek to clarify some confusion that appears now to exist surrounding the role of long-run marginal cost (LRMC) pricing, including what it is designed to achieve in principle and the forms that it can take in practice;
- in **section three**, we consider whether there is anything in the Consultation Paper that causes us to change our earlier conclusion regarding the efficiency of the price signals that would be delivered by the proposed charging approach;

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26 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper, Supplementary consultation*, 13 December 2016 (hereafter: 'Consultation Paper').

27 Axiom Economics, *Economic Review of Second Transmission Pricing Methodology Issues Paper, A Report for Transpower*, July 2016 (hereafter: 'Axiom July 2016 Report').

28 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper*, 17 May 2016 (hereafter: 'Second Issues Paper').

29 Oakley Greenwood, *Cost Benefit Analysis of Transmission Pricing Options, prepared for: NZ Electricity Authority*, 11 May 2016 (hereafter: 'OGW CBA').

30 Oakley Greenwood, *Response to issues raised on CBA, prepared for: Electricity Authority*, 2 December 2016 (hereafter: 'OGW Response to Issues'); and Oakley Greenwood, *Impact of the proposed changes to the TPM on the CBA*, 9 December 2016 (hereafter: 'OGW Impact of Changes').

- in **section four**, we assess whether any of the new material prompts us to change our conclusion that the proposal may not result in a more efficient or equitable allocation of the sunk costs of investments;
- in **section five**, we consider whether OGW's responses to the criticisms levelled at its proposals are sufficient to assuage those concerns and allow the Authority to place weight on the results of that modelling;
- in **section six**, we set out our key conclusions;
- in **appendix A**, we identify some specific problems with the proposed drafting of the transition mechanism in the Draft Guidelines; and
- in **appendix B**, we provide a list of all the earlier reports by Axiom economists containing analysis and conclusions that have informed this report.

Note that, in the interests of parsimony, we have tried not to repeat the analysis set out in our previous reports, except when necessary to address new material in the Consultation Paper or accompanying documents. For the avoidance of doubt, the conclusions set out in those earlier reports remain equally germane unless we indicate otherwise.[31] Finally, we stress that the opinions expressed throughout this report are our own and do not necessarily reflect the views of Transpower.

[31] For example, in some cases, points were raised in our previous report but are not addressed in the Consultation Paper or accompanying documents. In these instances, we tend not to repeat that earlier analysis – or, at least, not to nearly the same extent. However, it remains equally applicable.

2. What is LRMC pricing?

Our previous report explained the important differences between the *explicit* price signals that would be provided by LRMC charges (or modified versions of the RCPD and HVDC charges) and the *shadow* price signals that would be supplied by AoB charges. We explained why we thought that the latter would be a poor substitute for the former, and could result in inefficient operational and investment decisions.

Unfortunately, there appears to be some misunderstanding in the Consultation Paper about what an explicit *ex-ante* LRMC price would reflect and be designed to achieve in principle, and the various forms that it might take in practice. In this section, we seek to provide clarity on these points so that a more accurate assessment can be made of the relative merits of this approach to pricing *vis-à-vis* the Authority's proposal.

2.1 The principle of LRMC

An LRMC price is designed to signal the future costs that would be incurred from using more energy.

There has been a surprising degree of inconsistency across the various consultation documents regarding the basic economic principles underpinning LRMC pricing. In our opinion, this should not be a source of controversy or debate. An LRMC price is *forward-looking*, and designed to signal the *future costs* that would be incurred from using more energy, i.e., the long-run costs precipitated by an increase in demand. The Authority captured this concept nicely in its earlier LRMC Working Paper:[32]

> *'LRMC is forward looking, as it is the cost of future changes in capacity of the grid to meet future changes in demand.'*

This also mirrors the very similar sentiments expressed in the Authority's consultation paper on the potential effects of evolving technologies on distribution pricing structures:[33]

> *'…if the distribution network is at capacity, the marginal cost to deliver another unit of electricity is much higher – investment in new infrastructure will be needed. The cost of expanding the distribution network's capacity is taken into account as part of the long-run marginal cost of providing distribution services.'*

These approaches are also consistent with the conventional definition of LRMC adopted recently by the Australian Energy Market Commission. It defined LRMC as:[34]

32 Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.iii (hereafter: 'LRMC Working Paper').

33 Electricity Authority, *Implications of evolving technologies for pricing of distribution services*, *Consultation Paper*, 3 November 2015, p.10.

34 AEMC 2014, *Distribution Network Pricing Arrangements, Rule Determination*, 27 November 2014, Sydney, p.iii.

'…a measure that includes the future network costs that are incurred by using more energy, or the costs that could be saved by using less energy.'

The definition of LRMC in the Consultation Paper does not reflect accepted economic principles.

However, in a significant departure from the orthodox position taken in its previous LRMC Working Paper (presented above), the Authority states in the Consultation Paper that it now sees an LRMC charge:[35]

'…not as a forward looking price for future investment (even if it is calculated on the basis of the cost of future investment) but as a price that reflects the opportunity cost of the current use of a scarce resource – the existing grid. The user who benefits from the grid pays the LRMC charge not because future investment is required but because the opportunity cost of their use of the existing grid is the cost of denying another user the use of the existing grid.'

It is unclear why the Authority no longer views an LRMC charge as a forward-looking price for future investment. In our opinion, that is the accepted definition of LRMC pricing in economics. Unfortunately, the examples provided in the Consultation Paper do not provide a clear rationale for this change in interpretation. The first example invites the reader to:

It is unclear why the Authority no longer views an LRMC charge as a forward-looking price.

'Suppose that an existing line is becoming congested but that it is known with certainty that use of the line will never increase to the point where it is economically efficient to expand capacity on the line. Suppose for some reason nodal pricing does not apply to the line. Then a kWh charge (in the form of an LRMC charge) is necessary to limit use of the line to its capacity and so avoid the need to (inefficiently) expand its capacity. But it is not a forward looking charge for expanded capacity, because by assumption, the expanded capacity is never needed.'

We do not understand what this example is seeking to illustrate. It begins by asking the reader to assume that use of the line will never increase to the point at which it is efficient to expand it. That being the case, no dynamic pricing signal is needed to achieve static and dynamic efficiency. Yet it then contradicts itself by stating that an LRMC charge is needed to limit use of the line to avoid inefficient expansions. Given the prior assumption that an expansion will never be required – regardless of the level of usage – it is not clear why it is necessary to apply an LRMC charge – or *any* price – to curtail demand. These two facets of the example seem irreconcilable.[36]

35 Consultation Paper, p.35.

36 Perhaps what the example is trying to say is that if there is no charge at all, then the level of usage will increase and it might then be necessary to expand the line but, if an 'LRMC price' is set, the expansion will never happen, i.e., it will be deferred efficiently in perpetuity. And so, the logic may therefore be that the LRMC price could not possibly be a 'forward-looking price for future investment', since that future capacity never materialises. If that is indeed what the example is attempting to convey (which is unclear), it reflects a misunderstanding of LRMC pricing. The only circumstances in which an LRMC charge could curtail demand sufficiently to *permanently* avoid the line being expanded in this manner is if it is set at a level that reflects *the future costs that could be avoided* by using less energy. In other words, the LRMC charge would have to include some measure of the potential future expansion cost. The fact that the expansion might never actually happen is neither here nor there. The key point is that the LRMC charge would still factor in those avoided future costs – consistent with the conventional definition set out earlier.

We found the second example in the Consultation Paper just as puzzling. It claims that another hypothetical way of illustrating supposedly the same point is to:

> *'…assume that the line is congested in period 1 and its capacity is expanded for period 2. Assume that user A uses the line in period 1 but not period 2, while user B will use the line in period 2 but not period 1. Then user A would need to pay the LRMC charge, even though they never use the new line. User B would not, even though they do.'*

Here again, it is not clear to us what this example is seeking to convey. In this very stylised scenario, it is the demand from user A in period 1 that causes the need for the expansion. It is efficient for the potential future costs of that usage to be signalled at that time. The fact that the user is no longer around in period 2 to benefit from the investment might seem a little unfair, but it is not inefficient.[37] More generally, we do not understand how this example is pertinent to the interpretation of LRMC pricing set out in the Consultation Paper.

What the example *does* perhaps highlight is an important potential limitation with the *ex-ante* shadow price signals that would be provided under the proposed AoB charge. If user A knows that she would not use the line in period 2 – and that she would be assessed as deriving no private benefits from it when AoB charges are subsequently calculated – then she would have no incentive to change her current behaviour in ways that might defer the need for the investment. And user B obviously cannot change her behaviour in period 1, since she is not using the grid at that time, i.e., there is no behaviour to change.

For those reasons, the Consultation Paper does not contain any robust reasons for the change in the Authority's interpretation. That is perhaps unsurprising since, in our opinion, there is no sound basis in economics to conclude that LRMC is anything other than a forward-looking price for future investment. In this respect, the Authority has shifted from what was an economically orthodox definition of the principle of LRMC in its earlier LRMC Working Paper to a decidedly unorthodox interpretation in its latest Consultation Paper.

2.2 The practical design of LRMC prices

Various comparisons have been made throughout the Consultation Paper between 'beneficiaries pay' charging approaches (such as the AoB charge) and LRMC pricing – some explicit and some implicit. In our view, those assessments have been hindered to a significant degree by the very narrow view that appears to have been taken about how an LRMC charge would operate, in practice (we note that this was even a feature of the LRMC Working Paper, which contained an altogether more reasonable assessment of the merits of LRMC charging than either the Consultation Paper or the Second Issues Paper). The Authority has adhered to the view that LRMC charges would be:

37 If the Authority thinks otherwise, it is unclear why 'exacerbators pay' pricing assumes a higher position in its DME framework that 'beneficiaries pay' approaches.

- highly volatile over time and unstable at the point of investment, i.e., that they would 'reduce to zero' when new assets are commissioned which would, in turn, cause parties to agitate for investments to be undertaken sooner than is efficient to 'bring forward' those price drops;[38]

The Consultation Paper takes an unduly narrow view of how an LRMC price would be applied in practice.

- very 'granular', i.e., that they would apply to either very narrow geographic areas or to individual investments – resulting in the price volatility described above, and causing the Authority to conclude that such charges could be a plausible substitute for grid support contracts (see section 3.2.3);[39]
- highly 'inaccurate', since it is doubtful that Transpower or the regulator could assess the accuracy of the forecasts of demand and transmission investments, since these may change over time – including as technology changes – rendering the pricing less robust (see section 3.2.2.2);[40] and
- more complex to design and implement than either the status quo, or a combination of 'beneficiaries-pay' and 'residual' charges (such as the proposal set out in the Consultation Paper) – and it could undermine the price signal provided by, say, an AoB charge (see section 3.2.2.6).[41]

LRMC pricing is more nuanced than these unequivocal conclusions suggest. Although the underlying *principle* of an LRMC charge is relatively straightforward and uncontroversial – namely, to signal to users the cost of potential future grid expansions (see previous section) – there are numerous ways to design and implement such a price, in *practice*. Before an LRMC charge could be introduced, various choices would need to be made regarding:

- the methodology with which it would be calculated, e.g., whether to use a perturbation approach, an average incremental cost approach, etc.;

There are many ways in which an LRMC charge might be applied.

- the 'specificity' of the charge, including:
  - the geographic areas over which it would be calculated, e.g., for each node, for the four RCPD regions, for broader geographic areas, etc.; and
  - the period over which it would be measured (e.g., a 5-years, 10-years, or longer) and how often it would be updated; and
- whether it would be applied to load, generation or both.

The decisions that are made in relation to each of these key design options would have a profound influence over key factors such as the 'accuracy' of the resulting long-run price signals, the pattern of prices over time, the complexity of the methodology and the ease with which it can be accommodated alongside other charges. The Authority appears to be making key presumptions in relation to these design elements, without explaining their basis or contemplating any alternatives. And the alternatives are numerous.

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38 *See for example:* LRMC Working Paper, p.35.

39 *Ibid.*

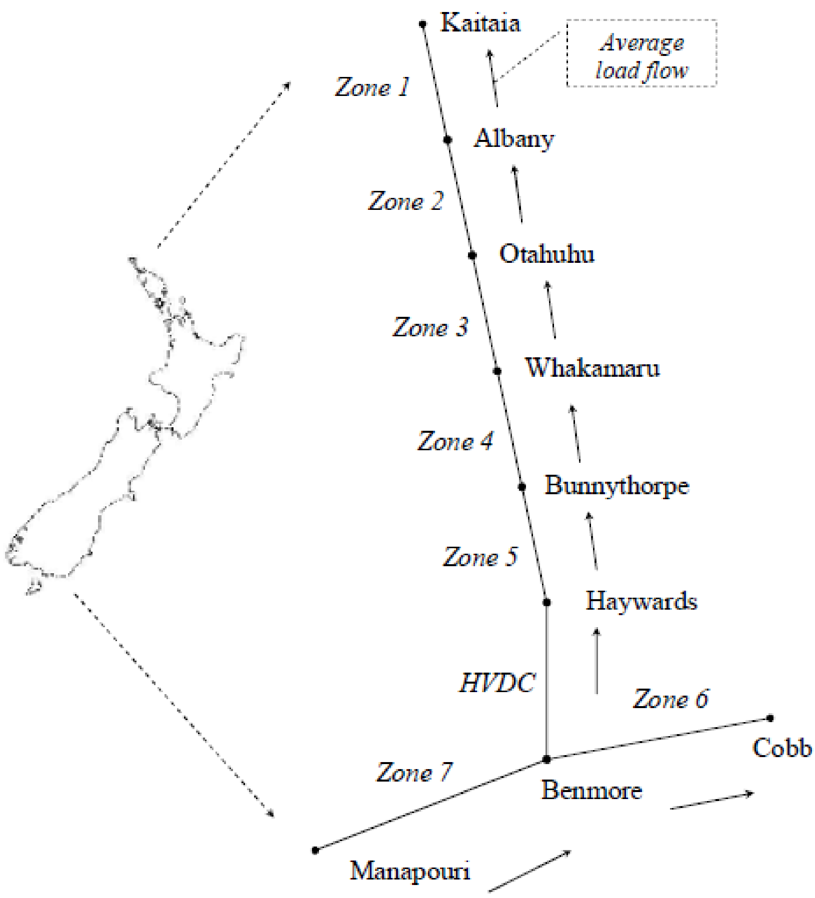
40 *See for example:* Consultation Paper, p.5 and LRMC Working Paper, p.37.

41 *See for example:* Consultation Paper, p.6 and LRMC Working Paper, p.38.

An LRMC charge could cover narrow geographic locations, or broader areas.

For example, in their report to the CEO Forum, Green *et al* (2009) proposed that an LRMC-based methodology might be applied to up to seven pricing zones, based on a simplified network topography – see Figure 2.1. Such a charge would be more granular than the existing four-region RCPD charge, but much less so than the highly-disaggregated approach that seems to be envisaged in both the Consultation Paper and the previous LRMC Working Paper. The potential variations on this design point are infinite.

Figure 2.1: Geographic pricing zones from Green *et al* (2009)



Source: Green *et al* (2009), *New Zealand Transmission Pricing Project: A report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, Figure 5.2, p.74.

An LRMC charge does not need to be highly volatile over time – it could be 'averaged' over a longer period.

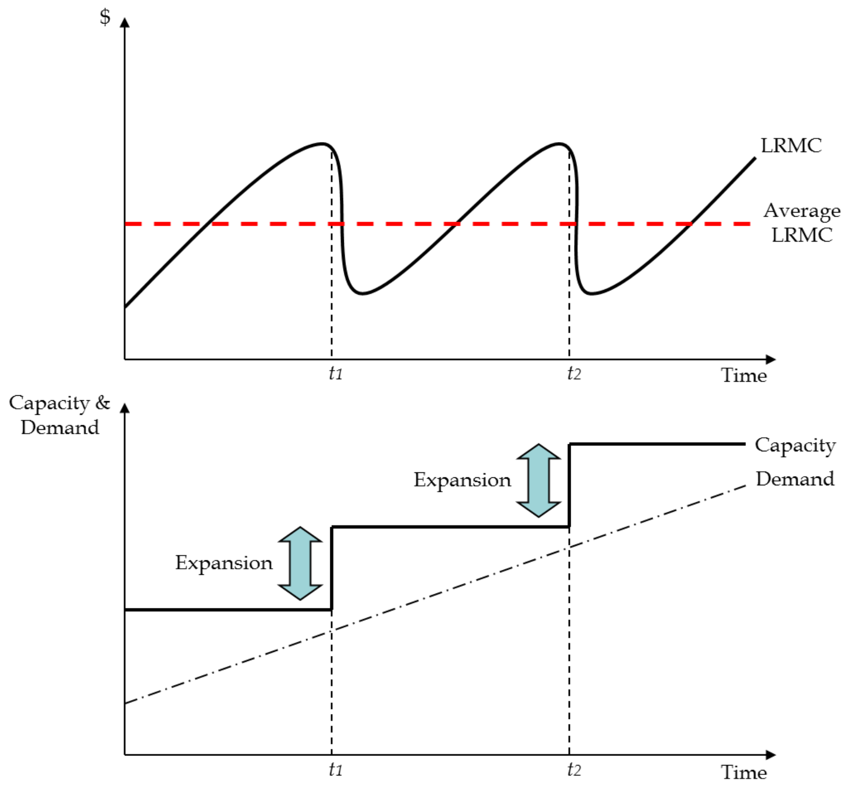
In a similar vein, an LRMC charge does not need to be highly volatile over time, declining precipitously after every investment. Applying the charge to broader geographic areas and to multiple investments would serve to reduce the fluctuations in those charges to some degree, and further stability could be achieved by adopting a longer measurement period. For example, Green *et al* (2009) recommended the adoption of a 20- to 30-year period, which would serve to 'smooth out' the typical 'saw-tooth' movements in LRMC.[42]

Figure 2.2 illustrates how such a charge might function. Although the LRMC would drop immediately following the investments at t_1 and t_2, if a longer measurement

42 Green *et al* (2009), *New Zealand Transmission Pricing Project: A report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.12 (hereafter: 'Green *et al* (2009)').

period was adopted, then the *average* LRMC could be relatively constant over time. Although setting prices based on the average LRMC over this longer period would, by definition, under- or over-estimate the current LRMC of capacity at any point in time in a particular location, it would provide a more stable signal over the longer-term – making it easier for grid user to predict and understand when making investment decisions.

Figure 2.2: Average LRMC charge



Many of the supposed problems with LRMC pricing that are raised in the Consultation Paper could be addressed by changing the way it is applied.

In other words, it is quite easy to envisage an LRMC charge that was relatively disaggregated in terms of its geographic coverage, yet quite stable in terms of the signal provided over time. That 'average' signal might then be bolstered, where necessary, by Transpower entering bespoke contracts for grid support with, say, generators, owners of storage solutions and/or providers of demand-response.[43] The Authority has not given any serious consideration to any options that include an LRMC charge exhibiting these traits – at least not explicitly.

To be clear, we are not necessarily recommending the type of LRMC charge proposed in, say, Green *el al* (2009) – although it could well be worthwhile. We are simply highlighting that the supposed disadvantages with LRMC pricing that have been highlighted throughout the consultation process are predicated on a very specific application of the concept. They are therefore not problems with LRMC

43 Note that this is essentially the approach taken to distribution pricing in Australia following the AEMC's recent changes, i.e., most distribution businesses have proposed a relatively broad-based LRMC (e.g., state-wide geographic coverage) augmented by network support payments. It is entirely possible that these approaches might become 'more granular' once the new methodology 'beds in' over time.

pricing *per se* but, at most, with one variant of it. It follows that the best solution to those issues may not be to dispense with LRMC pricing altogether but, rather, to simply adopt another practical application.

2.3 Summary

It is unclear what has prompted the Authority to change its view of the guiding economic principles underpinning LRMC pricing insofar as transmission pricing is concerned – especially given the orthodox approach it has maintained in respect of distribution pricing.[44] In our opinion, the accepted definition of LRMC pricing is inconsistent with the view expressed in the Consultation Paper: put simply, an LRMC price is designed to signal the *future costs* that would be incurred from using more energy. In a similar vein, the Authority appears to have taken an unduly narrow view of how an LRMC price would be implemented in practice.

The Consultation Paper adopts an unprincipled definition of LRMC and takes an overly narrow view of how such a price might work in practice.

Most notably, the Authority seems to believe that the prices would be highly volatile and applied either to very narrow geographic areas or to individual investments. All the supposed problems the Authority has identified with LRMC charges can be traced back to these key assumptions as to the basic design elements. Yet there is no need for an LRMC charge to take this form. It could instead be applied to broader geographic areas and designed to provide a more stable price signal over time, e.g., by applying to a longer time horizon. In other words, these potential problems could be addressed simply by adopting a different type of LRMC charge.

Much of the analysis of LRMC pricing set out in the Consultation Paper consequently rests on: a) a misunderstanding of the underlying economic principles; and/or b) any unduly narrow perspective of what an LRMC charge might look like, in practice. For the avoidance of doubt, throughout the remainder of this report, we adopt the economically orthodox definition of LRMC described above, and countenance practical applications of that concept that extend beyond the narrow formulation assumed in the Consultation Paper (and in earlier documents).

44 Electricity Authority, *Implications of evolving technologies for pricing of distribution services, Consultation Paper*, 3 November 2015, p.10.

3. Would there be efficient forward-looking price signals?

In our previous report, we concluded that the proposed suite of TPM changes – most notably the replacement of the RCPD and HVDC charges with an AoB charge – would not provide an efficient forward-looking price signal to customers of future costs before investments were made to elicit desirable changes in behaviour. Most notably, we explained why:

In our previous report, we concluded that the proposed methodology would not provide efficient forward-looking price signals.

- the explicit *ex-ante* price signals provided by nodal prices and losses would not provide sufficient signals to grid users of the costs that Transpower will incur in the long-run when it replaces or upgrades its assets; and
- the implicit *ex-ante* 'shadow price' signal provided by the AoB charge would not provide a predictable, accurate signal of Transpower's long-run costs to which grid users could respond – even if they were inclined to do so.

We concluded that for grid users to face an efficient signal of the potential future costs of investments in the interconnected grid, there must be an *explicit ex-ante* price signal. We stated that such a charge might be a variant of the existing RCPD and HVDC charges, or a new LRMC charge. In its Consultation Paper, these recommendations are dismissed for three key reasons; namely:[45]

- nodal prices are said to be sufficient to elicit efficient short- and long-run operational and investment decisions, obviating the need for an additional *ex-ante* price signal such as an LRMC charge;
- AoB charges are said to be able to provide a more efficient price signal than LRMC charges and it is said that grid support payments could also be relied upon to defer the need for future grid investment if required; and
- Transpower has the option of introducing an LRMC charge if it wishes, i.e., if it has exhausted all other options – the AoB charge and grid support payments – but still feels that an additional signal is needed.

We consider these reasons in turn below.

3.1 Do nodal prices signal sufficiently LRMC?

In our report in response to the Second Issues Paper, we explained the important role that nodal prices can play in efficiently rationing the demand for existing transmission grid assets. However, we cautioned that nodal prices alone may not provide sufficient signals to grid users of the costs that Transpower will incur in the long-run when it replaces or upgrades its assets. In other words, nodal price signals will not necessarily give rise to efficient investment in new assets. As we noted above, the Consultation Paper contends that our concern was misplaced:[46]

45 Consultation Paper, p.xiii.

46 Consultation Paper, p.5.

The Consultation Paper states that nodal prices can be relied upon to provide efficient short- and long-run price signals.

> *'... the Authority is of the view that submitters' concerns are overstated. Provided nodal prices are allowed to operate to limit the use of the grid to its capacity until new investment is justified, nodal price signals will coordinate grid use among different parties so that the available capacity is used by those that benefit most from it. As the second issues paper states, "the transport charge inherent in nodal prices provide price signals that encourage grid users to take into account the impact of their grid use on the timing of grid investments. In particular, the transport charge from the spot market should approach the marginal incremental cost of the corresponding amount of grid capacity in the years immediately before grid expansion is due to occur". Thus grid users act as if they are coordinating their actions to avoid inefficient investment.'*

The Consultation Paper therefore appears to be saying – quite categorically – that nodal prices can be relied upon to provide efficient short-run price signals *and* to provide efficient *long-run* signals as well. In other words, it is ostensibly claiming that nodal prices signals can give rise to efficient use of *existing* grid assets in the short-term and produce efficient investments in *new* grid assets over the longer-term. In the following sections, we evaluate this new proposition and whether it causes us to revise our previous views on the potential role of nodal pricing.

3.1.1 Inconsistencies with previous positions

This contention is inconsistent with the positions adopted in past papers.

The suggestion in the Consultation Paper that there is no need for an additional *ex-ante* price mechanism to prevent 'inefficiently early investment'[47] because nodal prices can do the job cannot be reconciled with the position the Authority has adopted previously. Hitherto, its unambiguous view has been that nodal prices *do not* provide efficient long-run signals for new investment. For example, the TPM Options Working Paper concluded that:[48]

> *'Although nodal pricing provides efficient short-run price signals for use of the grid,* ***it does not provide efficient long-run signals. Reliance on nodal pricing is insufficient to promote efficient transmission investment*** *because nodal pricing does not provide a sufficient price signal about the cost of the future transmission investment needed to supply changes in demand for transmission services.'* [our emphasis]

In the same vein, the LRMC Working Paper concluded that:[49]

> *'Some authors, such as Associate Professor James Bushnell of the University of California, Davis, who provided advice to Trustpower on the beneficiaries-pay working paper, suggest that nodal pricing is all that is required to promote efficient investment in relation to transmission. This appears to be based on a view that nodal pricing provides price signals that reflect both the SRMC and the LRMC for transmission. However,* ***nodal pricing is likely to result in price signals systematically below LRMC*** *... nodal prices are likely to under-*

47 Consultation Paper, p.5.

48 Electricity Authority, *Transmission Pricing Review, TPM options, Working paper,* 16 June 2015, p.53.

49 Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.29.

signal LRMC so ***LRMC charges could potentially promote more efficient investment****. However, while LRMC charges may be appropriate, nodal pricing will still provide some signal of marginal cost, albeit muted.'* [our emphasis]

No reasons are provided for this critical change of position.

There is nothing wrong with a regulator changing its mind. The peculiar aspect of this change of view stems instead from the lack of any explanation regarding the motivations. In our experience, when a regulator reverses its position it is customary for it to clearly set out its reasons – especially when it represents a critical part of the decision ultimately made, as is the case here. The absence of any explanation for the stark switch of position contained in the Consultation Paper is therefore decidedly unorthodox.

The change in opinion also creates a clear inconsistency between the views the Authority has expressed about the merits of LRMC pricing in the context of transmission pricing *vis-à-vis* the sentiments expressed in relation to *distribution* pricing. The Authority is now suggesting that there is no need for an LRMC-based peak pricing signal in the TPM. Yet, when it assessed the pricing methodologies of distribution businesses in 2015, it concluded that one of the chief problems with the dominant charging methodology was that:[50]

> *'…there is no price signal to network users of the marginal cost of new capacity'*

And that:[51]

> *'Signalling the cost of new capacity involves pricing approaches that reflect the cost of supplying more capacity at times a network is congested (at which time demand on the network will be at its peak).'*

In other words, the Authority considered the absence of LRMC-based peak price signals to be highly problematic, and urged distribution businesses to introduce them. It is not clear to us why LRMC charging would be considered meritorious – if not *necessary* – in the context of distribution pricing, but not so in the case of transmission pricing. From our perspective, in each instance the basic economic principles are the same.

There appears to be a further irreconcilable conflict within the proposed methodology itself: namely, between the price signals supposedly provided by nodal pricing, and those said to be provided by the AoB charge. A hefty portion of the Second Issues Paper was devoted to setting out the beneficial effects that the AoB charge would purportedly deliver by providing an additional *ex-ante* shadow price signal. For example, the paper claimed that the charge would provide grid users with:[52]

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50 Electricity Authority, *Implications of evolving technologies for pricing of distribution services, Consultation Paper*, 3 November 2015, p.65.

51 *Ibid.*

52 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper,* 17 May 2016, p.88.

> *'…better incentives than the current HVDC and interconnection charges to take into account the cost of upgrades to the interconnected grid when making their own operational and investment decisions, and when considering Transpower's proposals for upgrades to the interconnected grid.'*

If nodal prices were sufficient to provide efficient price signals the TPM would become an exercise in pure ex-post cost allocation.

If the new proposition in the Consultation Paper is correct, and nodal pricing can be relied upon to provide *all* the signals that grid users need to make efficient decisions, then why would the AoB charge need to send any signal? Indeed, why would there need to be any *ex-ante* price signals in the TPM at all? If the new interpretation is accurate, then nodal pricing would be all that was needed to ensure that the right investments were made at the right times. It would be futile to try and elicit further responses from grid users via the TPM, since this could only compromise static and dynamic efficiency.

Instead, the only role for the TPM would be to allocate and recover the costs of investments in the least distortionary manner possible once they have been made. In other words, the sole goal of the TPM would be to *stop* grid users from changing their behaviour once efficient investments have been elicited via nodal pricing, i.e., the exclusive aim of the TPM would be to not impinge upon those perfectly efficient short- and long-run price signals. The exercise would become one of pure *ex-post* cost allocation, ideally involving no *ex-ante* price signalling whatsoever.

However, the scenario described above is plainly not what is contemplated in either the Second Issues Paper or the Consultation Paper. In both cases, AoB charges (and other mechanisms such as grid support payments) are clearly seen to have an important role to play signalling long-run costs. These myriad inconsistencies mean that we have not been able to discern the rationale for this fresh proposition in the Consultation Paper. In any event, whatever the motivation, it would not be robust given the basic economics of transmission services, as we explain below.

3.1.2 Inconsistencies with the economics of transmission

The contention that nodal prices can provide efficient long-run investment signals assumes that the market dynamics mimic workable competition.

The Consultation Paper's contention that nodal prices provide both efficient short- and long-run signals rests crucially on the assumption that they should mimic those seen over time in a competitive market. Most notably, the paper suggests that in the years immediately before a grid expansion occurs, nodal prices will approach 'the marginal incremental cost of the corresponding amount of grid capacity'.[53] Put another way, it is implied that new investments will occur when nodal prices (the 'short-run marginal cost' (SRMC) of transmission) have risen to the point at which they reflect the LRMC of expanding supply.

The phenomenon described above is what one would expect to see in an unregulated competitive market. To see why, suppose for the sake of illustration that there is currently only one hotel in a small town, but that the market is competitive, i.e., there are no barriers stopping other hoteliers from entering. In the short-run, the number of hotel rooms in town is fixed. This means that the most

53 Consultation Paper, p.5.

efficient way to deal with excess demand during peak periods would be to increase the prices for the existing rooms.[54] This is because:

- it would not be possible to construct a new hotel or expand the existing building in the near-term, e.g., to find a site, obtain planning approvals, arrange financing, undertake construction, and so on; and
- those investment decisions would not be based solely on one period of high prices in any event – rather, it is the expected returns over a longer time horizon that would be relevant for entry/expansion decisions.

However, if demand kept growing to the point where the hotel was constantly increasing its prices to curtail demand then it may be more efficient to build more rooms, i.e., to expand supply. In unregulated competitive markets, this 'tipping point' occurs when the expected cost of *curtailing* demand (as represented by the SRMC) increases beyond the cost of expanding capacity to *meet* it (as represented by the LRMC) – either via new firms entering, or existing suppliers expanding. At that point, efficient new investment would take place.[55]

However, as we explained in our previous report,[56] this relationship between SRMC and LRMC that is observed in unregulated competitive markets *does not apply* in the context of electricity transmission services. To see why, suppose that the hotel from our earlier example is *not* free to set whatever prices it likes for its rooms. Suppose instead that it is subject to several important practical constraints. For example, imagine that:

Once practical constraints are applied, the investment outcomes change.

- there is a maximum price that the hotel may set per room, irrespective of the level of demand, e.g., a cap of $1,000 per room per night, even though some customers might be prepared to pay more;
- most of its guests book their rooms through an intermediary that 'smooths out' the fluctuations in the prices charged by the hotel and offers customers an 'averaged' price that largely disguises any 'peaks' and 'troughs'; and
- the hotel has an obligation to ensure that there is always enough rooms to accommodate anybody that wants one, i.e., an explicit 'social obligation' to ensure that supply can always meet demand.

Would one still expect to see the same new investments happening at the same times? Almost certainly not. The most likely outcome is that the hotel and/or new entrants would invest sooner and, potentially, build bigger. Why? Because the practical constraints listed above would serve to prevent hoteliers from allowing

54 Similarly, if the hotel experienced a temporary period of low prices due to reduced demand it is not going to respond in the near term by reducing the number of rooms or by exiting the market.

55 Specifically, as Green *et al* (2011) explain, in the long-run, once firms in competitive markets have had time to expand or reduce their capacity, one would not expect to see SRMC-based prices that are significantly and persistently above the LRMC of adding capacity, or below the long-run avoidable cost (LRAC) associated with reducing capacity. In other words, in the long run, in competitive markets, prices should equal both SRMC and LRMC. *See:* Green *et al*, *Potential Generator Market Power in the NEM, A Report for the AEMC*, 22 June 2011.

56 Axiom July 2016 Report, pp.4-8 and Appendix A.

room prices to ever reach the levels that would signal to customers the LRMC of expanding capacity. As such, customers would never see a price that signalled to them the consequences of their actions on long-term investment costs, i.e., there would be a 'missing signal'.

Transmission services are not provided in a competitive market, and so investments are made before SRMC=LRMC.

The situation is the same in the context of electricity transmission services. As we highlighted in our previous report – and the Authority itself acknowledged in its LRMC Working Paper[57] - there are sound, practical reasons why new transmission investments might be made before nodal prices ever reach the levels that would signal to grid customers the LRMC of those grid expansions. These include the following:[58]

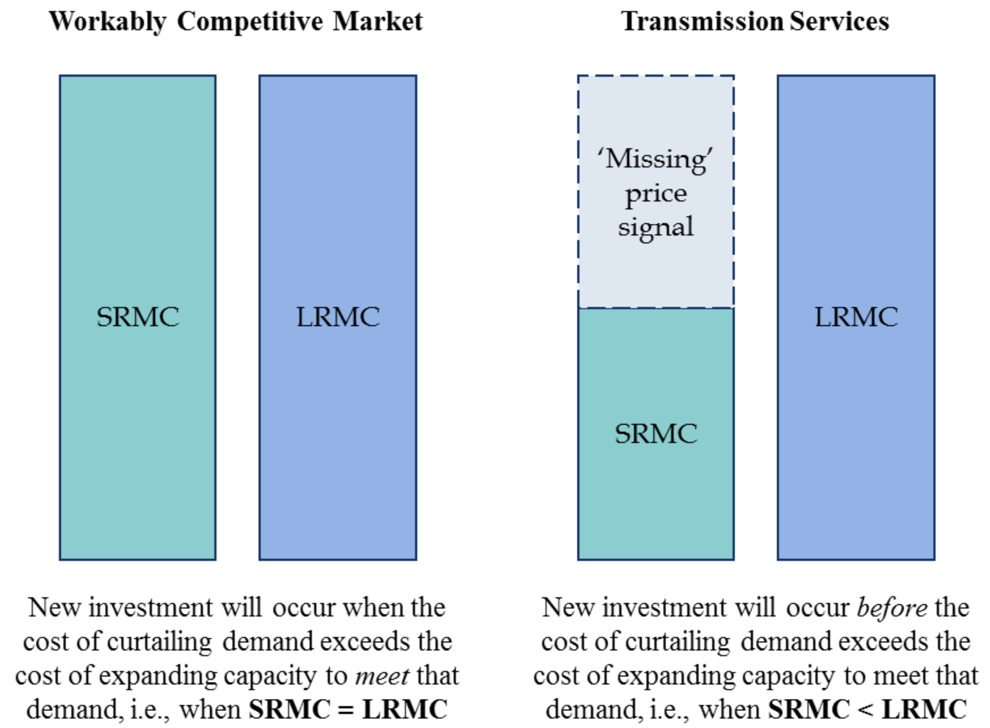
- if nodal prices are capped below the true value to customers of lost load, spot price differences will be highly unlikely to reflect the LRMC of the network (this is the 'transmission equivalent' of the $1,000/night cap on hotel room prices in our previous example);
- most 'final' electricity customers are insulated from the immediate impacts of nodal prices through the 'risk aggregation' function served by their retailers (this is the 'transmission equivalent' of the intermediary 'smoothing' room prices from the previous example); and
- transmission planners justifiably and efficiently 'err on the side of caution' when investing in new capacity – building sooner rather than later, and they also use reliability standards (e.g., the N-1 standard for the core grid) that are independent of economic costs (this is the 'transmission equivalent' of the obligation to provide a room to 'all-comers' in our earlier example);

Transpower is therefore more analogous to the 'constrained' hotel from our earlier example. It might not be able to wait for nodal prices to increase to the level of LRMC before investing, since that might risk 'the lights going out' or breaching its reliability standards (and the 'signalling' ability of nodal prices is limited in any event). In the absence of some other *ex-ante* price signal, it might therefore need to invest in new grid capacity *before* nodal prices hit LRMC (i.e., new grid could be built when SRMC < LRMC). Figure 3.1 from our previous report illustrates.

57 Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.30.

58 Note also that market power problems may lead to overbuilding transmission to promote competition generally in power markets and there are valid national security reasons to overbuild transmission rather than risk the comparatively more severe consequences of underinvestment.

Figure 3.1: Gap between SRMC and LRMC



Nodal prices will systematically under-signal the LRMC of transmission resulting in a 'missing' price signal.

To be clear, this would not involve Transpower expanding the grid 'before the investment is justified'. The outcome would simply reflect the basic economics of providing transmission services that cannot reasonably be ignored. In the absence of some other additional price signal, today's grid users may therefore not factor the potential consequences of their actions for Transpower's long-run investment costs into their consumption and investment decisions. For example:

This does not constitute Transpower investing inefficiently.

- a load customer may decide not to curtail its demand in a peak period in response to a higher nodal price (e.g., a 'higher' SRMC), and that incremental demand may 'bring forward' the need to undertake a new investment; and
- because of the factors described above, the new investment may take place before nodal prices increase to a level that reflects the LRMC of that investment, in which case the customer would *never see* the 'true costs' of its actions.

It follows that, for customers to be made aware of the consequences of their actions on Transpower's *future* costs *before* they are incurred, something beyond the signal provided by nodal prices is needed. An additional signal is required that conveys to customers in some way the 'gap' that exists between the SMRC and LRMC of transmission. As we explained in our previous report, an LRMC price is one way that Transpower could send the 'missing signal' not provided by nodal prices, thereby potentially giving rise to more efficient investment outcomes.[59]

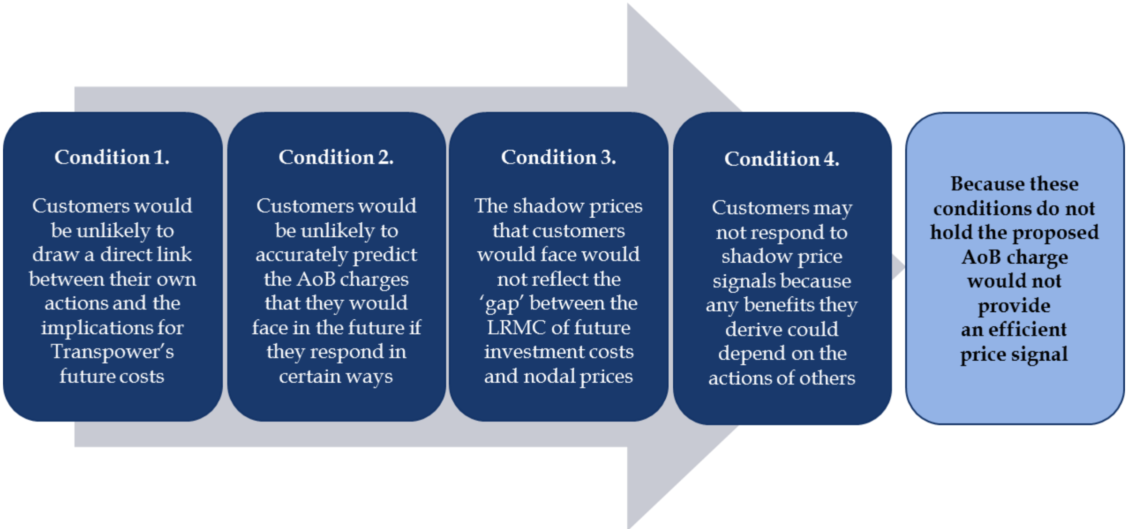
[59] This would be analogous to the 'constrained hotelier' in our earlier having the option of applying an extra 'peak season surcharge' that could be added to the standard room charge, enabling customers to pay a price that reflected the true LRMC.

Our previous report explained why the four key conditions for an efficient shadow price do not hold.

3.2 Would the proposal provide an efficient price signal?

Four key conditions must hold before an implicit shadow price like the proposed AoB charge could provide an efficient forward-looking price signal in the case of interconnection assets, obviating the need for an *explicit ex-ante* price signal such as an LRMC price (or modified RCPD and HVDC charges).[60] Our previous report explained why these conditions *do not hold* in this context, and why the AoB charge would therefore risk compromising dynamic efficiency. Figure 3.2 summarises the reasons we presented.

Figure 3.2: The conditions for an efficient shadow price do not hold



We consequently concluded that the AoB charge would not provide customers with the right incentives to make efficient consumption and investment decisions if it was introduced. More specifically, we stated the proposed AoB charge could not be relied on to 'address the gap' that exists between nodal prices and LRMC, highlighted in Figure 3.1. Below, we consider whether there is any new analysis presented in the Consultation Paper that has caused us to revise that conclusion.

3.2.1 Assessment of the conditions for efficient shadow pricing

The Consultation Paper continues to maintain that the AoB charge would provide an efficient forward-looking shadow price signal that would be superior to that provided by an LRMC charge (or modified RCPD and HVDC charges). However, that conclusion is reached after only an abbreviated analysis of the four conditions for efficient shadow pricing raised in our previous report. In terms of the first two conditions summarised in Figure 3.2, the Consultation Paper states simply that:[61]

> *'…some submitters argued that some consumers would not anticipate future AoB charges, either because they would not be forward looking or*

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60 Our prior report stated that these conditions could well hold in the case of dedicated connection assets, where further investment needs are typically quite clear, and where it is usually the actions of one party – i.e., the connecting customer – that is driving those investment needs.

61 Consultation Paper, p.5.

because they would not get the information to make forward looking decisions. The Authority is of the view that Transpower will have an incentive to provide this information to its customers. It also considers that distributors will have the incentive to ensure that its customers are aware of and take account of future increases in transmission charges.'

Customers could not be forward-looking, even if they were so inclined.

This represents a substantial oversimplification of the points raised in our previous report. We did not say that customers *would not* be forward looking, but that they *could not be* – at least not in the manner required to elicit efficient operational and investment outcomes.[62] We explained that most customers would not be able to predict with any real accuracy the AoB charges that they would face over the 40- to 50-year life of a transmission asset under all the different potential 'states of the world'.[63] The Authority agreed with this assessment in its Distributed Generation Consultation Paper, in which it concluded that:[64]

*'…there would be a significant impediment to distributors and owners of distributed generation agreeing to such contracts. **This is because they are unlikely to have the full information needed to determine what transmission investments might be required, and how the operation of distributed generation could defer the investment**. One consequence of this lack of information would be that distributors could not be confident that Transpower would actually defer the transmission investment(s) as a result of the operation of the distributed generation.'* [our emphasis]

Transpower could not overcome this problem simply by providing customers with information.

Furthermore, this problem cannot simply be 'assumed away' by presuming that Transpower would provide customers with all the information they need to predict charges and respond appropriately. We acknowledged in our previous report[65] that Transpower could certainly *help* by providing regular updates to customers on its future investment programmes. As part of that process it might even seek to identify what was driving those investment needs, provide indicative charges, and even specify steps that might be taken to defer those costs. But, even if it did so:[66]

- not all customers would read and understand a planning document, let alone fully comprehend the links between their individual consumption and investment decisions and Transpower's future investment requirements; and
- it may be difficult, in practice, for distribution businesses to signal to 'final load customers' (a key demographic) the future costs of potential future grid expansions that are not *explicitly* priced into the TPM *today*.

For those reasons, we do not consider that the Consultation Paper has addressed adequately the informational obstacles that customers would confront when faced

62 Axiom July 2016 Report, pp.16-17.

63 *op.cit.*, pp.15-17.

64 Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2-E.3.

65 Axiom July 2016 Report, p.16.

66 *op. cit.*, pp.16-17

with the challenge of drawing a link between their current actions and their potential future AoB charges. And even if customers could draw such links, the paper does not provide a robust explanation for why they would be inclined to respond efficiently to those shadow price signals when faced with potential 'tragedies of the commons'. The potential for such phenomena is acknowledged in the Consultation Paper, but it goes on to state that:[67]

Tragedies of the commons could arise, and these would not be assuaged by nodal price signals.

> *'…submitters' concerns are overstated. Provided nodal prices are allowed to operate to limit the use of the grid to its capacity until new investment is justified, nodal price signals will coordinate grid use among different parties so that the available capacity is used by those that benefit most from it. As the second issues paper states, "the transport charge inherent in nodal prices provide price signals that encourage grid users to take into account the impact of their grid use on the timing of grid investments. In particular, the transport charge from the spot market should approach the marginal incremental cost of the corresponding amount of grid capacity in the years immediately before grid expansion is due to occur". Thus grid users act as if they are coordinating their actions to avoid inefficient investment.'*

In other words, the Consultation Paper contends that tragedies of the commons are unlikely to occur, because nodal prices can be relied upon to produce efficient usage and investment decisions in both the short- and long-run. As we explained earlier, this assertion is incorrect as a matter of economics and is inconsistent with the Authority's previous positions on this point. Nodal prices *cannot* be relied upon to prevent tragedies of the commons and elicit efficient investment outcomes because:

- they will systematically *under-signal* the long-run cost of future grid expansions, i.e., investments will occur before SRMC equals LRMC because of the basic economics of providing transmission services; and
- as we explained in our previous report,[68] grid users may rationally choose not to take efficient actions (e.g., investing in distributed generation), since the benefits they receive from doing so may depend on the actions of others.

Moreover, there is a logical inconsistency in the claim that AoB charges would result in efficient outcomes – and avoid tragedies of the commons – because *a completely separate* nodal pricing signal will 'do all of the work'. As we explained above, if that were so, then the TPM would not need to provide any *ex-ante* price signals at all since that would ultimately be counterproductive. In other words, it represents a peculiar defence of the AoB charge because, if it were true, it would suggest the charge serves no obvious purpose.

The charges that individual customers would face would not reflect LRMC.

Finally, even if nodal prices were, indeed, all that were needed to produce efficient outcomes, this still would not detract from the final shortcoming in the AoB charge – namely, the fact that it is sending the wrong price signals (the third condition in

67 Consultation Paper, p.5.

68 Axiom July 2016 Report, pp.19-20.

Figure 3.2). As we explained in our prior report,[69] any price signals provided by the AoB charges in combination with nodal prices would be inefficient, since they *would not reflect LRMC*. We highlighted that while LRMC may fluctuate over time, at any point in time it is a single, unique number[70] that is agnostic to *particular customers*, i.e., LRMC does not change depending upon whom the charge is being levied upon.

In contrast, the proposed design of the AoB charge means that there would be an array of *multiple* implicit shadow prices for each future investment – each of which reflected an individual customer's perceived share of private benefits, and all of which could be above or below the LRMC of transmission which, remember, is a single number. The inevitable result would be non-cost-reflective price signals that could provide customers with inefficient incentives. For example, imagine that 'customer A' would derive, say, twice the 'private benefits' of 'customer B' from a forecast new investment:

Under the proposal, customers would not face 'cost-reflective' charges.

- with an explicit *ex-ante* LRMC price, this would not affect the size of the price signal that each would face under an explicit LRMC charge – it would be *the same* for both customers, irrespective of their projected 'future private benefits' because, after all, the LRMC is a single number; whereas
- under the proposed AoB charge, the shadow price faced by 'customer A' (assuming she can predict it) would be twice as high as that faced by 'customer B', providing the counterintuitive signal that a demand response from that customer is worth twice as much – when, in truth, the LRMC is the same.

This represents a critical shortcoming in the proposed approach. Put simply, it would not represent a 'cost-reflective' methodology – a cornerstone of the Authority's elaborated version of the decision-making framework. Yet despite the seriousness of this methodological flaw, the only place that the Consultation Paper touches upon the divergence between AoB charges and LRMC prices is in its evaluation of Oakley Greenwood's cost-benefit analysis – and then only in passing. It states that:[71]

> *'…it is reasonable to model the Authority's proposal as an LRMC charge because that is a reasonable proxy for the AoB charge that a forward-looking consumer would face if transmission investment was in fact imminent.'*

This statement would only be correct when a *single* customer was facing an AoB charge and knew that to be so, i.e., a situation analogous to a bespoke connection charge. However, that would rarely – if ever – be the case.[72] The rest of the time an interconnection investment would entail multiple potential beneficiaries and the 'shadow prices' that those individual customers perceived could each be well above

69 *op cit.*, pp.17-19.

70 Note that the number itself may differ depending on the methodology with which it is calculated, but each approach will always yield a single number.

71 Consultation Paper, Appendix D, p.3.

72 If it was, then the investment in question would almost certainly be a connection asset.

or below the level at which an explicit LRMC charge would be set which, for the reasons set out above (and in our previous report), would be inefficient.

Finally, levying AoB charges on generators would also create several more specific potential problems. Most notably, for the reasons set out in our previous reports (and which we do not repeat here), charging generators in the manner contemplated gives rise to the following inefficiencies:

- the proposal to allocate AoB charges to generators based on their average injections when calculating bespoke private benefits is not practicable could cause generators to factor those transmission costs into their offer prices, thereby compromising the efficiency of the wholesale market;
- depending upon how AoB charges are assigned to new entrant generators (a matter upon which the Draft Guidelines provide no real instruction) this might affect the size and/or nature of the plant that is installed, e.g., a generator might decide to install a smaller plant to avoid paying a higher AoB charge;
- levying an additional fixed charge on generators would also increase the average expected wholesale electricity price required to make new generation investments commercially viable,[73] resulting in higher future wholesale prices than would otherwise have been the case;[74] and
- under the 'base proposal', the AoB charge would provide the counterintuitive signal to generators (and load customers, although they are less likely to respond to it) that it is 'cheaper' for them to invest in areas supplied predominantly by assets built before 2004 (although, Transpower would have the option of broadening the application of the charge to encompass more historical investments).

We remain of the view that the proposal would not comply with the four key conditions for efficient shadow pricing.

We therefore consider that only a token attempt has been made in the Consultation Paper to address the issues we raised in our previous report regarding the shortcomings in the price signal provided by the proposed AoB charge. We consequently have not changed our conclusion on this key point. We continue to consider that the conditions for an efficient shadow price *do not hold* and that the methodology risks giving rise to inefficient consumption and investment decisions, relative to an explicit *ex-ante* price signal such as an LRMC charge.

3.2.2 Purported advantages of the AoB charge over an LRMC charge

The Consultation Paper seeks to highlight some advantages of the proposed AoB charge over an explicit LRMC price. It is worth reiterating at the outset that this

73 Specifically, it would increase a new generator's 'break-even' points, i.e., it would render a generator that was only marginally profitable under the existing TPM, unprofitable. Wholesale electricity prices would therefore have to increase to cover existing generators' higher costs. This is consistent with what one would expect to observe in any competitive market when input prices increase, i.e., those higher costs are passed-through to some degree.

74 It may serve to delay the point at which new generation plant comes online – or change the 'build order'. This would not be problematic if those decisions were being made in response to an efficient, cost-reflective price signal of long-run transmission costs. However, for the reasons set out above, the AoB charge would not provide such a signal. *See:* Axiom July 2016 Report, pp.27-28.

assessment in the Consultation Paper is difficult to reconcile with the favourable statements the Authority has made about LRMC pricing in the distribution pricing context. It is similarly difficult to square with the conclusion in the LRMC Working paper that, compared with beneficiaries-pay charges (of which the AoB charge is a variant):[75]

> *'LRMC charges are market-like and are therefore, in principle,* ***more preferred*** *under the Authority's decision-making and economic framework.'* [our emphasis]

Setting aside these apparent inconsistencies, in our opinion, there is another significant overarching problem with the assessments, and many others that are more specific in nature. The general shortcoming relates to the assumptions being made about the essential features of the two charging methodologies under review; namely:

The paper contrasts an unduly narrow version of an LRMC charge with an idealised and unrealistic variant of the AoB charge.

- the presumption appears to be that the LRMC price would take a very particular form – i.e., the narrow formulation described in section 2.2, when its design and application may be quite different in practice – and all the challenges associated with designing and implementing such a charge are emphasised acutely throughout the assessment; whereas
- the assumption seems to be that the AoB charge would function highly effectively, i.e., that all customers would be able to predict their future charges, that those prices would be cost-reflective and that there would be no 'tragedies of the commons' when, for the reasons set out in 3.2.1, that does not provide a realistic depiction of how the methodology would operate, in practice.

In other words, the Consultation Paper is contrasting an unduly narrow version of an LRMC charge – with all its flaws – with an idealised and unrealistic variant of the AoB charge. This type of comparison cannot provide useful insight into the respective merits of the two approaches. As we explain below, once a more measured assessment is undertaken, the various purported advantages of the AoB charge largely fall away and, in our view, it is apparent that an LRMC charge could well offer greater potential benefits.

3.2.2.1 Parties only have to pay AoB charges if an investment is made

Providing an explicit price signal before investments are made reveals whether those outlays are efficient.

The Consultation Paper claims that one relative advantage of the AoB charge is that: 'it need only be applied after the investment has been made, so parties would only have to pay the charge if the investment was actually made.'[76] The inference seems to be if an explicit price signal is provided before a potential investment is made that signals those future costs, and it ultimately does not proceed, that somehow represents a problem. If that is indeed what is being suggested, it reveals a misunderstanding of the purpose of sending an explicit *ex-ante* price signal.

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75 Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.iii.

76 Consultation Paper, p.5.

One of the key potential advantages of establishing an explicit *ex ante* price that signals potential future costs is that, if customers do not value those prospective future investments highly enough to pay for them, then they will respond by curtailing demand, obviating the need for them. When that happens, it is a *good* thing. It is better to find that out that customers do not value an investment sufficiently *before* it is made, rather than only *afterwards* when customers are forced to pay for something they do not want (or the assets are stranded).

In contrast, the AoB charge's shadow price signal would not be predictable or cost-reflective.

In contrast, the problem with the *ex-ante* shadow price signals that would be provided via the AoB charge is that they would be neither predictable nor cost-reflective (i.e., customer's prices would not reflect LRMC) and could give rise to tragedies of the commons. It is therefore an imperfect substitute for an *explicit ex-ante* charge like an LRMC price. All these shortcomings could mean that investments are made that *should not* be made (or, at least, not at that time). The fact that customers would only start paying for those inefficient investments after they have gone ahead – and not before – would be no source of solace.[77]

3.2.2.2 AoB charges would be more accurate than LRMC charges

This appears to be a false comparison between an ex-post allocation of costs and an ex-ante price signal.

A further purported advantage of the AoB charge is that: 'it relates to the actual Transpower investment that is made and so would be accurate, whereas there is a risk an *ex ante* LRMC-type charge would provide an inaccurate signal if the investment or its timing changes.'[78] This appears to be a false comparison between an *ex-post* allocation of costs and an *ex-ante* price signal. The former is obviously 'more accurate' than the latter, because:

- once an investment has been made, the sum is known and the cost allocation is, of course, 'accurate'; whereas
- any *ex-ante* LRMC price (or indeed, any *ex-ante* price at all) would be the product of imperfect information about the level of potential future costs.

The shadow price signal provided by an AoB charge may not be more accurate than that supplied by an LRMC price.

But that is beside the point. The only relevant comparison is between the accuracy of the *ex-ante* price signals that would be provided by an AoB and an LRMC charge, respectively, *before* an investment is made. As we set out above, the *ex-ante* shadow price signals provided through the AoB charge would not be 'accurate' in any real sense, since they would be neither predicable nor cost-reflective (i.e., the charges that individual customers perceive may not reflect LRMC).

Perhaps even more importantly, once an investment has been made, although the 'total sum' to be recovered is known, the private benefits that individual customers

77 We note also the clear inconsistency between this purported advantage of the AoB charge and the marginal benefit adjustment mechanism (MBAM) that still features as a part of the proposal. Recall that any party that avails itself of the MBAM can only ever be compensated for the costs it has incurred (e.g., investing in distributed generation) once the (now less expensive) transmission investment has been made. If that transmission investment never actually occurs, then the party is paid nothing – in which case the MBAM collapses.

78 Consultation Paper, p.5.

will derive from it over its life *are not.* As our previous report explained,[79] it would not be possible to forecast private benefits with any degree of accuracy over the 40- to 50-year life of an interconnection asset. In other words, while Transpower would know the 'size of the pie', dividing it up 'accurately' would be an altogether different matter.

In contrast, the 'accuracy' of an explicit *ex-ante* LRMC charge depends to a large degree upon how it is implemented. As we explained in section 2.2:

- a 'highly granular' price that related to narrow geographic areas or bespoke investments would provide a more accurate signal, but the downsides would be the added complexity and, potentially, more price volatility; and
- a more 'aggregated' price signal that encompassed more locations and/or investments would be simpler to administer and more stable, but it would be less 'accurate' (i.e., less likely to reflect LRMC in any time and place).[80]

In other words, it is not correct to conclude that AoB charges would be more accurate than LRMC charges. The *ex-ante* shadow price signals provided by the former would be unpredictable and 'inaccurate' (i.e., not cost-reflective) almost all the time.[81] Moreover, the *ex-post* allocation exercise itself would inevitably be prone to error, given the challenges associated with estimating private benefits.

Conversely, the accuracy of the explicit price signals provided by an LRMC charge depends upon the way in it is calculated and applied. Moreover, it is worth remembering that 'more accurate' charges are not necessarily more efficient in any event – especially if they are very costly to design and implement, or impractical, e.g., result in highly volatile prices.

3.2.2.3 AoB charges can be readily applied to different types of investments

Another supposed strength of the AoB charge relative to an LRMC charge is that 'it is flexible so can readily be applied to different types of investments including those not motivated by savings from reducing losses and relieving constraints such as some reliability investments.'[82] The suggestion seems to be that an LRMC charge would have 'no work to do' insofar as reliability investments are concerned, since any reductions in demand would not affect the timing or size of those outlays.

If the contention is correct, an LRMC charge would have a role to play in signalling the cost of reliability investments.

There are only two possibilities here. The first is that the contention is incorrect, in which case an LRMC charge (or some other form of explicit *ex-ante* price signal) *would* have a potential role to play in signalling the future costs of reliability

[79] Axiom Economics, *Economic Review of Second Transmission Pricing Methodology Issues Paper, A Report for Transpower,* July 2016, pp.37-39.

[80] However, as we noted earlier, to the extent that an aggregated LRMC price 'under-signalled' the need for grid support in a particular location, Transpower might seek to address that by entering into bespoke network support contracts.

[81] The only exception would be where a single customer was facing an AoB charge and knew that to be the case – a scenario analogous to a bespoke connection charge.

[82] Consultation Paper, p.5.

investments, potentially, influencing their size and/or timing. If that is the case then, in our view, it could well be more efficient at doing so than an AoB charge, given the aforementioned shortcomings with its shadow price signals.

If the contention does not hold, there is no need to send a price signal of any kind – including via an AoB charge.

The second possibility is that the statement is correct, which would simply mean that there was no use in sending an *ex-ante* price signal *of any kind* – including via the proposed AoB charge. Indeed, if sending an *ex-ante* price signal (either explicit or implicit) could not affect customers' behaviour in a way that changes beneficially the timing or size of reliability investments, then it follows that a non-distortionary residual charge should be applied to those types of investments.

Either way, it is not correct to conclude that an AoB charge would be 'more flexible' than an LRMC charge. In in our opinion, the considerable degree of latitude that Transpower would have over the key LRMC charge design parameters such as its geographic coverage and the measurement periods suggests that, if anything, the opposite is more likely to be true.

3.2.2.4 AoB charges incentivise participation in investment processes

Introducing an AoB charge would not have a beneficial effect on the new investment approval process.

The Consultation Paper states that another benefit of the AoB charge *vis-à-vis* an LRMC charge is that: 'it provides a strong incentive on parties to participate in the investment approval process.'[83] For the reasons we have set out in detail in our earlier reports[84] (and do not repeat here) we do not consider that introducing an AoB charge would have a beneficial effect on the new investment approval process. Rather, it is altogether more likely to have a negative impact by creating more unconstructive opposition to all investment proposals.

3.2.2.5 It ensures that only the parties that benefit pay for an investment

This again presumes that the price signals provided by an AoB charge would be efficient.

The Authority considers another advantage of the proposed AoB charge over an LRMC charge to be that: 'it ensures that only those parties that benefit from an investment would pay for it, which makes it more durable.'[85] Once again, this presupposes that the shadow price signals that would be provided by an AoB charge would elicit efficient investment outcomes. In our opinion, relative to an LRMC charge, there is a greater chance that beneficiaries would wind up paying for inefficient investments, which would compromise the durability of the methodology.

Furthermore, an LRMC charge provides an explicit signal of the cost of future investments to customers and allows them to respond if it is beneficial for them to do so. In other words, sending an explicit price signal allows customers to *decide for themselves* whether to respond and to maximise their own private benefits in the process, much like in a workably competitive market. There is no need for

83 Consultation Paper, p.6.

84 *See most recently:* Axiom July 2016 Report, pp.30-32.

85 Consultation Paper, p.6.

Transpower – or a regulator – to estimate what different customers' private benefits might be when setting that price.

In contrast, the AoB charge would require Transpower to assess what customers' private benefits would be and to charge them accordingly. As we explained in our previous reports (and in section 4.2),[86] it would not be possible for Transpower to forecast with any meaningful precision the temporal dynamics of private benefits over the 30- to 50-year (or thereabouts) life of an interconnection asset when deriving AoB charges.

Transpower would not be able to estimate perfectly customers' private benefits.

Transpower would need to make judgement calls in relation to a multitude of factors to estimate private benefits over such a long window, e.g., about future nodal price levels, hydrological and meteorological conditions, and so on. These decisions would inevitably entail large degrees of subjectivity and judgement, which could create big 'winners and losers'. It is natural to expect that the losers would be very vocal in their opposition. In our opinion, this would be a recipe for endless disputes – not improved durability.

3.2.2.6 It can readily be applied in combination with other charges

The final advantage of an AoB charge is said to be that: 'it can readily be applied in combination with other charges, including an LRMC charge, in ways that do not undermine the accuracy of the price signal provided by the AoB charge.' There are several problems with this contention. First, it assumes that the shadow price signal being provided by the AoB charge would be 'accurate'. As we have seen already, it would not be. The charge would be neither cost-reflective (in that customers' individual charges may not reflect LRMC) nor predictable.

The assumption is that any LRMC charge must fit in with an AoB charge, not the other way around.

Second, it seems to presuppose that any LRMC charge must fit in with an AoB charge, and not the other way around. This appears to be a consequence of the peculiar way that the Authority has applied its decision-making and economic (DME) framework. Because the options that occupy higher positions in the DME framework – including an LRMC charge – would not allow Transpower to recover 100% of its revenue requirement, the Authority goes sequentially down the list – eventually finding itself at 'beneficiaries-pay' charges (the penultimate option) and then, finally, to 'alternative approaches' (the last option).

It follows that the only circumstances in which the TPM would *not* include any 'beneficiaries-pay' charging is in the unlikely scenario in which the options that occupy higher rungs on the hierarchy could deliver Transpower its entire revenue requirement, without the need for an 'alternative approach' as a 'back-up' (such as the proposed residual charge). The rest of the time, the TPM would presumably include an element of the penultimate option – in this case, an AoB charge. This approach was perhaps expressed most clearly in the earlier LRMC Working Paper, which explained that:[87]

86 *See most recently:* Axiom July 2016 Report, pp.37-39.

87 LRMC Working Paper, p.vi.

'if [sic] LRMC charges were applied but did not fully recover Transpower's, costs ***the Authority's decision-making and economic framework implies a beneficiaries-pay charge should be applied to recover remaining costs****. The combination of LRMC and beneficiaries-pay charges, and possibly residual charges, would be more complex than the status quo.'* [our emphasis]

This flips the DME framework on its head, elevating 'beneficiaries-pay' charges to the 'top' of the hierarchy.

This serves to flip the DME framework on its head. The penultimate option – 'beneficiaries-pay' charging – is effectively elevated to become the indispensable feature of any TPM, despite its relatively low position in the hierarchy of potential approaches. This is reflected plainly in the attitude expressed towards LRMC pricing throughout the Consultation Paper. Even though LRMC charges are ostensibly to be preferred based on the Authority's own DME framework,[88] the continual focus is upon whether they can be accommodated alongside AoB charges – not the reverse.

If the DME framework was working in the manner that was presumably intended (noting the serious reservations that we have expressed about its usefulness in the past[89]), the rebuttable assumption would be that an *LRMC charge* (or some other market-based or exacerbators-pay option) would form part of the TPM and the question would be whether an AoB charge could sit effectively alongside it. If it could not, then the logical next step would be to move down to the next rung in the ladder, i.e., to a residual charge. Dispensing with the *superior* option represents a counterintuitive application of the decision-making tool.

3.2.3 Could grid support payments be relied upon?

Three conditions must apply before a grid support contract is a viable option.

The Consultation Paper introduces the notion that Transpower could use grid support payments to curtail demand or elicit additional supply if spot prices (and AoB charges) did not do so sufficiently.[90] It would only be *after that option had been exhausted* that an LRMC price might have a potential role to play.[91] In our opinion, there would be several problems with such an approach. To see why, it is important to recognise the circumstances in which a bespoke payment to a party for grid support *would* be a viable – and efficient – option for Transpower to pursue. For that to be the case, three conditions must hold:

- Transpower must be able to identify an option – or options – for procuring the required amount of network support, i.e., a potential solution must exist;

88 Recall that the Authority acknowledged this in its LRMC Working Paper: *see:* Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.iii.

89 *See for example:* Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper*, *A Report for Transpower,* March 2014, section 2.3.1.

90 Note that this is inconsistent with statements made elsewhere in the Consultation Paper that suggest – categorically – that nodal pricing is all that is needed to elicit efficient short- and long-term operational and investment decisions. *See for example:* Consultation Paper, p.5.

91 In other words, an LRMC charge would be the 'last cab off the rank', despite the rather lofty position that it occupies in the DME framework. This seems counterintuitive, for the reasons set out in the previous section.

- Transpower must be able to implement that solution quickly and cheaply enough, accounting for transaction costs; and
- Transpower must have the inclination to pursue the option, recognising it would always have the 'safe and familiar' option of building a network solution.

These conditions would not always hold. It would not always be possible for Transpower to identify viable contracting opportunities for procuring network support. As we explained in detail in our report in response to the Authority's Distributed Generation Consultation Paper,[92] bespoke grid support payments tend to work best when there is something 'big and obvious' that Transpower can do, e.g., contract with a large, underutilised distributed generator. Those options may simply not exist.

Potential network support options may be disaggregated and hard to coordinate.

Instead, the potential options might be quite 'disaggregated' and hard to coordinate, i.e., larger numbers of smaller distributed generators, or potential 'demand responders'. The transaction costs associated with large numbers of smaller parties may outweigh considerably any benefits that Transpower might receive from each of them.[93] Moreover, when faced with the alternative of simply building a network solution, it is easy to envisage situations where investments are made that might have been deferred or downsized if an explicit price signal had been provided.

To illustrate, imagine that Transpower was yet to invest the $3b or so it has recently outlaid on the grid and that the RCPD charge was still in place (or, alternatively, an explicit LRMC charge). It is safe to assume that those charges would be having some effect in alleviating transmission congestion. Now, suppose that those explicit *ex-ante* charges vanished. Could Transpower replicate the same level of demand response via bespoke grid support payments without incurring undue costs? In our opinion, the answer would almost certainly be: 'no'.

A superior approach may be to provide an explicit ex-ante price signal and then bolster it through grid support contracts where necessary.

In other words, just as an AoB charge is an imperfect substitute for an explicit *ex-ante* charge (in that it is unpredictable, not cost-reflective and susceptible to tragedies of the commons), so too are grid support payments. In our opinion, a potentially superior approach would be for Transpower to first provide *all* customers with incentives to curtail demand (or increase supply) through the application of an explicit *ex-ante* LRMC charge. If that produced the desired level of network support, there would then be no need for it to do anything else.

However, if Transpower felt that it was necessary to procure additional network support to potentially defer a pending investment – say, because the LRMC charge was 'averaged' and was under-signalling the *true* LRMC in a location – it might then seek out opportunities to enter into grid support contracts. As we noted earlier, this

92 Axiom Economics, *Economic Review of Distributed Generation Pricing Principles Consultation Paper, A Report for Transpower*, July 2016, pp.47-53.

93 In some circumstances, it may be possible for a smaller providers of network support to combine their output in some way (e.g., through an external aggregator creating a portfolio), thereby allowing Transpower to contract with a single party. However, this is unlikely to be an option all the time for precisely the same reasons, e.g., it may be difficult for disparate parties to coordinate – or for an aggregator to assemble them.

is the approach that is taken to distribution pricing in Australia.[94] In our opinion, this may represent a more appropriate use of the available 'regulatory tools', i.e., pricing vs. bespoke contracting.

3.2.4 Relegation of the marginal benefit adjustment mechanism

An important feature of the proposal in the Second Issues Paper was a 'marginal benefit adjustment mechanism' (MBAM). The idea was for Transpower to, in effect, supply each customer an indicative future bill and say: "this is what you will have to pay, unless something changes." Customers would then have the opportunity to provide it with 'credible commitments' to take steps that might downsize – or delay – that investment. They would then be compensated in the form of reduced AoB charges once the investment had been made.

Relegation of the MBAM is a welcome step, but it does not fix the problem it was originally designed to address.

The basic objective of the MBAM was to replicate the outcomes that would arise under a conventional explicit *ex-ante* charge, such as an LRMC charge, where customers have clear incentives to respond in efficient ways to the delivered price signal. However, several serious problems were identified – by both ourselves[95] and other submitters – with both the theory underpinning the MBAM and the issues that it would create for Transpower, in practice (which we do not repeat here).

The Consultation Paper acknowledges these problems and relegates the MBAM from a mandatory component of the proposal to an option that Transpower could choose to pursue (with some small modifications).[96] However, this is not accompanied by any other changes to the proposal aimed at addressing the problem that the MBAM was trying to solve in the first place, i.e., the inability of the AoB charge to mimic the outcome of an explicit *ex-ante* price such as an LRMC charge. It therefore represents a somewhat incomplete response to the concerns that were expressed by submitters.

3.3 Is it sufficient for an LRMC charge to be an option?

The Consultation Paper states that Transpower always has the option of implementing an LRMC charge if it considers that the combination of nodal prices, AoB charges and grid support payments would not be sufficient to elicit efficient outcomes from grid users. The implication is that there is therefore no need to make an LRMC charge a compulsory part of any TPM guideline. In addition to contradicting the DME framework (see earlier discussion in section 3.2.2.6), this contention rests on two unsound assumptions:

- that the combination of nodal prices, AoB charges and grid support payments AoB charge could normally be relied upon to produce efficient outcomes; and

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94 Following the AEMC's recent distribution network pricing rule change, most Australian distribution businesses have proposed a relatively broad-based LRMC (e.g., state-wide geographic coverage) augmented by network support payments (see: here).

95 Axiom July 2016 Report, pp.20-23.

96 It is not obvious why Transpower would have any appetite to implement such an option, given the significant problems it would create for itself by doing so.

- when they could not, that Transpower would be willing and able to propose an LRMC charge if the current proposed Guidelines remained unchanged.

In our opinion, neither of these assumptions is likely to hold. For the reasons described hitherto (and in our previous report), nodal prices, AoB charges and grid support payments would not always provide grid users and Transpower with incentives to make efficient operating and investment decisions. Instead, in the absence of an additional explicit *ex-ante* price such as an LRMC charge, the proposal would often be sending inefficient price signals that compromised significantly static and dynamic efficiency.

Transpower may be unwilling to propose LRMC charges, given the unfavourable views expressed about them in the paper.

Moreover, Transpower may *not* be prepared to devote the time and resources that would be required to design an LRMC charge. It will undoubtedly have noted the unfavourable views expressed about the need for LRMC pricing throughout the Consultation Paper – and earlier consultation documents. Indeed, there are places in the paper where it is suggested quite categorically that an LRMC price is not necessary – the discussion of the role of nodal prices being the most obvious example.[97] That being the case, it is not obvious why Transpower would be inclined to invest the effort required to propose such a charge, given the seemingly high probability of rejection.

Furthermore, it seems that the Authority would be prepared to countenance only a very specific type of LRMC price, i.e., a highly granular charge that would be applied in a particular location where everything else had been tried. It appears unlikely that it would look favourably upon, say, a 'broader charge' the likes of which was proposed by Green *et al* (2009). The Consultation Paper suggests the Authority would conclude (wrongly, in our view) that this type of LRMC charge was unwarranted, because the AoB charge would serve the same function. This may diminish further Transpower's appetite to propose such a charge.

3.4 Summary

We do not understand the contention in the Consultation Paper that nodal prices can be relied upon to provide efficient short-run price signals *and* to provide efficient *long-run* signals. It is inconsistent with accepted economic theory and with the Authority's previous positions. In our opinion, nodal prices *cannot* be relied upon to deliver efficient long-term pricing signals of future investment costs. There is therefore a potential role for the TPM to play in 'plugging this gap'. There is also a wide variety of ways in which an LRMC charge might assist in that respect, depending upon the way it is designed and implemented.

97 *See:* Consultation Paper, p.5.

There is similarly nothing in the Consultation Paper that causes us to change our opinion that the four key conditions for efficient shadow pricing do not hold for the proposed AoB charge. The paper does not identify any other legitimate advantages that AoB charges would have over LRMC prices – the comparisons made in this respect are not valid. The paper also does not address the various potential inefficiencies that may arise from levying AoB charges on generators. Furthermore, in our view, bespoke grid support payments cannot serve as an effective *primary* vehicle for eliciting network support. They should instead play an ancillary role to an explicit *ex-ante* price signal, such as an LRMC charge.

We remain of the opinion that the proposed methodology would not provide efficient forward-looking price signals.

Finally, the fact that Transpower would retain the option of introducing an LRMC charge under the proposed Guidelines does not mean that it would be inclined to do so, or that efficient operational and investment outcomes would arise in its absence. In our opinion, neither would be very likely. For those reasons, the material set out in the Consultation Paper has not caused us to alter our conclusion that the proposed reforms – and the AoB charge in particular – could not be relied upon to provide efficient signals to customers of future costs before investments are made to elicit desirable changes in behaviour.

Table 3.1 provides a summary of all the points that we raised in relation to the price signals provided by the proposed methodology in our previous report, and whether they have been considered and addressed satisfactorily.

Table 3.1: Would there be an efficient forward-looking price signal?

Issues raised in previous report		Outcome
Sufficiency of nodal price signals.	Nodal prices would not adequately signal Transpower's forward-looking costs, and so an additional *explicit ex-ante* price signal is needed to plug that gap, e.g., an LRMC charge or a modified version of the RCPD charge.	Considered but unresolved
The AoB charge would not provide an efficient 'shadow-price' signal that would effectively 'plug the gap' between nodal prices and LRMC	Customers would be unlikely to draw a direct link between their own actions and the implications for Transpower's future costs	Considered but unresolved
	Customers would be unlikely to accurately predict the AoB charges that they would fact in the future if they respond in certain ways.	Considered but unresolved
	The shadow prices that customers would face would not reflect the 'gap' between the LRMC of future investment costs and nodal prices.	Not considered[98]
	Customers may not respond to the shadow price signals, because any benefits they derive could depend on the actions of others, resulting in 'tragedies of the commons'.	Considered but unresolved
	The proposed marginal benefit adjustment mechanism (MBAM) would not address the problems listed above and would create other significant problems.	Considered and partly resolved[99]
Application of AoB charges to generators.	The AoB methodology could give rise to inefficient consumption and investment decisions by generators.	Unresolved

98 The Consultation Paper does touch very fleetingly upon the divergence between AoB charges and LRMC prices is in its evaluation of OGWS's CBA. However, it comprises a single declarative statement with no accompanying analysis. *See:* Consultation Paper, Appendix D, p.3.

99 The proposal to relegate the mechanism to an optional component of the methodology is welcome, but it does not address the broader problems surrounding the inefficiency of the price signals.

4. Would there be a more efficient allocation of sunk costs?

Once we had concluded in our previous report that the proposed methodology would be unlikely to provide an efficient forward-looking price signal *before* investments were made, we turned our attention to whether it might result in a more efficient allocation of sunk costs *after* investments had been made. We observed that:

In our previous report, we concluded that the proposed approach may not produce a more efficient allocation of sunk investment costs.

- changing the way in which sunk costs are allocated by implementing an AoB charging methodology may not improve allocative efficiency;
- the AoB charging approach would be likely to give rise to significant additional costs, i.e., reduce productive inefficiency; and
- the proposed residual charge on load could give rise to distortions and be considered unfair.

We concluded consequently that the proposal may not result in a more efficient or fairer allocation of sunk investment costs. Below, we assess the responses provided to these various points in the Consultation Paper – including several changes to the proposed charging methodology – and explain whether they cause us to revise our previous conclusion.

4.1 Are significant allocative efficiency gains achievable?

In our previous report, we identified several key reasons why we considered that changing the way in which sunk costs are allocated by implementing an AoB charging methodology may *not* improve allocative efficiency. They were the following:

- while any inefficient load shedding would cease if the proposal was implemented, this would be due simply to the removal of the RCPD charge, not the introduction of the AoB charge, e.g., an LRMC charge could do the same;[100]
- there were allocative inefficiencies arising from the HAMI-based parameter on the HVDC charge, but these have diminished significantly following the announcement of the SIMI-based parameter;[101]
- imposing a substantial amount of additional transmission charges on final load customers would be likely to result in a reduction in demand, which would give rise to an allocative efficiency loss;[102]

100 Axiom July 2016 Report, pp.34-37.

101 *op cit.*, p.35.

102 *op cit.*, p.36.

- levying AoB charges on generators may give rise to various distortions to consumption and investment decisions, which could compromise both allocative and dynamic efficiency;[103] and
- the earlier proposal to apply depreciated historical cost (DHC) charges to existing assets earmarked for AoB charges was unnecessary and would have resulted in an inefficient time profile of prices.[104]

In terms of the first point, we agreed with the observation in the Second Issues Paper that load customers may currently have undue incentives to reduce their use of sunk interconnection assets during peak periods to avoid RCPD charges. We acknowledged this may be a source of static inefficiency, given the spare capacity that now exists throughout much of the grid. However, we explained that the achievement of any such allocative efficiency gains would not hinge on the introduction of an AoB charge.

Rather, to eliminate any such inefficient unserved demand, one would simply need to remove – or reduce the strength of – the existing RCPD charge signal. We noted that this could be achieved in several ways, e.g., by replacing it with an LRMC charge, or by measuring contributions to RCPD over a larger number of peak periods, to diminish customers' incentives to avoid the charge. The Consultation Paper seeks to address this point by observing that:[105]

> *'The Authority's approach is also far more efficient than the suggestion of some submitters of a refined regional coincident peak demand (RCPD) charge, because a RCPD charge would provide a price signal that, at best, would only approximate LRMC for some nodes and some time periods, whereas the proposed guidelines provide the potential for a price signal to reflect LRMC.'*

The AoB charge would not necessarily be more efficient than a modified RCPD charge or an LRMC charge.

We agree that an RCPD charge would only approximate the LRMC of transmission – we recognised this in our previous report.[106] However, as we explained above, the AoB charge would not provide price signals that reflected LRMC *either*. It would therefore not necessarily be more efficient than a modified RCPD charge or, more importantly, an explicit LRMC-based charge. We therefore remain of the view that there are likely to be more effective ways to address any allocative efficiencies arising under the current RCPD charge.

The Consultation Paper does not address the second and third reasons listed above. As such, we have no reason to alter our conclusions. Namely, we remain of the view that the shift to the SIMI-parameter has largely addressed the problems associated with generators strategically withholding capacity and, in our view, allocating such a large amount of additional transmission charges to load customers would result in some allocative inefficiency (see further discussion in section 5.1.2).

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103 *op cit.*, pp.27-30.

104 *op cit.*, pp.40-41.

105 Consultation Paper, p.6.

106 Axiom July 2016 Report, p.9.

As we explained earlier, the revised proposal does not resolve the potential inefficiencies that may result from levying AoB charges on generators. Most notably, the Draft Guidelines require Transpower to allocate AoB charges to generators based on their average injections when calculating private benefits is not practicable. This has the potential to distort wholesale market outcomes, since generators may seek to temporarily withhold supply if they think that by doing so they might receive lower transmission charges, moving forward.

Finally, the Consultation Paper seeks to address the problems that would have arisen from applying DHC charges to certain existing assets by proposing the use of an indexed historical cost (IHC) approach for *all* assets. This may indeed serve to reduce any allocative inefficiencies that might otherwise have been associated with the previous proposal.[107] However, the same outcome could be achieved by applying the replacement cost approach currently used by Transpower for connection assets, thereby avoiding design and implementation costs.

We remain of the opinion that the proposal would not improve allocative efficiency, relative to alternatives.

For those reasons, on balance, the new material in the Consultation Paper has not caused us to change our original conclusion. We therefore remain of the view that the proposal – even in its revised form – is unlikely to result in any improvement in allocative efficiency; at least not relative to alternative approaches including, most notably, a methodology that included an LRMC charge as a core component.

4.2 Potential impacts upon productive efficiency

Our previous report highlighted several reasons why the proposed AoB charging approach would be likely to give rise to significant additional costs, i.e., productive inefficiencies. We explained that:

Transpower would face additional costs estimating private benefits.

- additional costs would be incurred estimating private benefits, which would increase with the complexity of the methodology adopted;[108]
- additional costs would be associated with the increase in lobbying and disputes that would be expected to follow the introduction of such a charge; and
- there would be ongoing disruptions associated with the application of the MBAM, applications for prudent discounts, and so on.

In terms of the first point, we explained why it would not be possible for Transpower to forecast with any meaningful precision the temporal dynamics of private benefits over the 30- to 50-year (or thereabouts) life of an interconnection asset when deriving AoB charges.[109] We noted also that these challenges could not

107 We note also that extending the application of the AoB charge to include all past investments would reduce the inefficient incentive that customers might otherwise have had under the previous proposal to invest in areas in which the interconnection assets were 'older', i.e., built before 2004. *See:* Axiom July 2016 Report, pp.29-30.

108 Axiom July 2016 Report, pp.37-38.

109 *op cit.*, p.37.

be overcome by using more sophisticated approaches to estimating private benefits – such as the vSPD method.[110] That would amount simply to false precision.

The Consultation Paper seeks to address this problem in the revised proposed Guidelines by providing Transpower with more flexibility to trade-off accuracy against practicability.[111] The Draft Guidelines are ostensibly more accommodating of more 'aggregated' approaches to estimating private benefits. Specifically, they state that, in determining the annual amount to be recovered under the AoB charge, Transpower must promote an efficient trade-off between:[112]

- the economic benefit of sending accurate price signals to customers; and
- the economic cost of developing, implementing, and administering the valuation method.

In our opinion, however well-intentioned this change may be, it is not altogether clear how Transpower could strike an appropriate balance between these two objectives. The simple reason for this is that, for the reasons we set out earlier (and in our previous report), the AoB charge *would not send accurate, cost-reflective price signals to customers*. Put simply, how can Transpower apply the methodology so as to send accurate price signals when the approach itself precludes it?

In addition to this fundamental issue which, in our opinion, cannot be resolved without major changes to the proposal (e.g., replacing the AoB charge with an LRMC charge), several other problems that we raised in our previous report also remain unaddressed, including:

- how customers that enter an 'area of benefit' after an investment has been made would be assigned a share of the costs of those sunk assets – the Consultation Paper provides no guidance on this crucial point;[113] and
- the lack of clarity surrounding the practical distinction – if any – between the 'standardised' and 'simplified' methodologies, particularly if a more aggregated approach is used to measure private benefits.[114]

The proposed guideline allows Transpower more discretion, but introduces other new challenges.

Moreover, the proposed changes to the methodology – and to the Draft Guidelines – introduce a host of other complexities and uncertainties that Transpower would need to address when measuring private benefits and allocating charges more generally, such as:

- developing and implementing a new IHC asset valuation methodology (a step which, for the reasons we set out above, does not seem to be necessary given the option of simply retaining the existing replacement cost methodology);

110 Axiom July 2016 Report, pp.37-38.

111 Consultation Paper, p.14.

112 Draft Guidelines, clause 28.

113 Axiom July 2016 Report, pp.28-29.

114 Axiom July 2016 Report, p.39.

- preparing a methodology for 'scaling back' its transmission charges in those years in which the application of those charges would otherwise lead to over-recovery of its annual revenue requirement;[115] and
- how is should go about identifying and modelling the 'most likely scenarios' when modelling private benefits (from which it would then be required to take an 'arithmetic average' to determine customers' allocations).[116]

There would be more costs associated with lobbying and disputes.

We therefore remain of the view that Transpower would need to incur substantial additional costs developing these opaque aspects of the methodology and then applying it to estimate private benefits. This would be accompanied by a considerable increase in the level of lobbying and disputes – the second point listed above. As we explained in section 3.2.2.5 above, Transpower would need to make substantial judgement calls in relation to a multitude of factors to estimate private benefits. These decisions would inevitably create 'winners and losers'.

It is natural to expect that the losers would be very vocal in their opposition to those decisions. Parties can be expected to fixate upon the assumptions underpinning their respective benefit calculations. Because many of these would be intrinsically subjective (i.e., have no 'unambiguously correct' answers) and impossible to 'lock in' up-front[117] (i.e., to 'set and forget'), this would be a recipe for ongoing controversy and productive inefficiency. The Consultation Paper does not address this second point and so our conclusion remains the same.

The revised scope of the PDP and relegation of the MBAM are welcome steps.

Finally, the Consultation Paper does include some measures that would serve to reduce some of the ongoing disruptions that Transpower would face under the proposal. Most notably, the paper proposes not to extend the prudent discount policy (PDP) to encompass the exit of load and to relegate the MBAM to an optional component of the methodology. However, while these changes are useful, the many other factors set out above would still serve to increase the costs associated with the proposed methodology.

We remain of the view that the proposal would harm productive efficiency.

The new material contained in the Consultation Paper therefore has not prompted us to revise the conclusion set out in our previous report. We remain of the opinion that the proposed methodology could result in a substantial increase in costs, i.e., reduced productive efficiency. It is also unclear to us how Transpower could feasibly comply with certain elements of the Draft Guidelines, e.g., how it would strike an appropriate balance between 'accuracy and simplicity' when the AoB methodology itself would appear to preclude the former.

115 *See:* Consultation Paper, pp.22-24.

116 *op cit.*, pp.15-16.

117 *op cit.*, p.32.

4.3 Allocation of the residual charge

Our previous report noted that the proposed residual charge on load could give rise to distortions and might, in some circumstances, be considered unfair. We based this conclusion on the following:

- there would still be some risk of customers inefficiently changing their conduct – particularly as the time approaches for the residual charge to be 'reset';[118]
- the significant wealth redistributions that would occur under the proposal might be viewed by some customers as inequitable and a form of 'hold-up';[119] and
- it seemed neither necessary nor desirable to limit the potential residual charge allocation options that Transpower has as its disposal in the Guideline.[120]

The proposed residual charge could distort customers' decisions.

With respect to the first point, we explained that residual charges could affect customers' investment decisions. We noted that a customer might decide to 'build small' *every* time it invested in lines or transformers, with a view to receiving a significant pay-off several years hence. Furthermore, that incentive would grow over time as the 'reset' of residual charge approached. The Consultation Paper does not address this point, and so we remain of the same opinion.

In terms of the second point, we observed that the proposed approach raised questions related to the 'fairness' of the reallocation of sunk costs. For example, we noted that it could be said to be somewhat 'unfair' to change the way in which past costs are allocated, so soon after a major investment programme. We also highlighted that the wealth transfers were very large, and fell disproportionately on load customers – often with anomalous results. For example:

- in some cases, customers' residual charges were inflated considerably relative to other customers' in similar circumstances, simply because of the configuration of their transmission assets;[121] and
- the proposed period for calculating anytime maximum demand (AMD) did not account for significant changes in some customers' demand, such as the departure of a major load.[122]

The Consultation Paper proposes to assuage these problems by revising the Draft Guidelines to direct Transpower to:

- "correct for double counting and other charging anomalies" when calculating residual charges;[123]

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118 Axiom July 2016 Report, p.45.

119 *op cit.*, pp.45-46.

120 *op cit.*, pp.46-47.

121 *See:* Consultation Paper, pp.31-32.

122 *op cit.*, p.32.

123 Draft Proposed Guideline, clause 32(b).

- levy residual charges that "result in broadly equivalent charges to customers that are in broadly equivalent circumstances";[124] and
- cap the annual increases in transmission charges that EDBs and direct-connect customers would face for 'pre-guideline' assets.[125]

The proposed guideline contains several features designed to ensure fairer charges, but these may not be effective and basic problem remains.

Although the intention underpinning the first two proposals is virtuous, in our opinion, the Draft Guidelines themselves are unhelpfully vague. For example, it is unclear what is meant by key term such as "other charging anomalies" or "broadly equivalent circumstances". These terms are not defined and there is a wide array of potential interpretations. To take an obvious example, would EA Networks – which is facing much higher charges under this proposal – be considered to be 'in broadly equivalent circumstances' to its neighbouring networks?

On the one hand, one might say: "of course – it uses many of the same transmission assets as its neighbouring networks, and so it stands to reason that its charges should be broadly equivalent". On the other hand, it is quite easy to imagine parties pointing to various 'network-specific' factors as potential sources of differentiation. Given the clear potential for such ambiguities, Transpower could well have considerable difficulty putting these clauses into effect.

In addition, the proposal does not address arguably the chief source of potential inequity – namely, the large reallocation of sunk costs so soon after a major investment programme. The proposed price cap is presumably intended to take some of the 'sting' out of the resulting price increases but, as we explain in more detail in Appendix A, there are two significant flaws in the way it is currently specified in the Draft Guidelines; namely:

- the design of the mechanism assumes that the other components of customers' energy bills – e.g., energy prices – will change at the same rate as the CPI, which is unlikely to be the case, undermining the workability of the price cap; and
- the cap may cease to be meaningful if Transpower introduces other 'additional' charges that sit outside it, e.g., if it extends the application of the AoB charge to significantly more assets, or introduces an LRMC charge.

The move away from an exhaustive list of allocators is a welcome step.

Furthermore, even if these problems were addressed by revising the drafting in the proposed Guidelines, the broader problem would remain. As we explained in our report in response to the August 2015 TPM Options Working Paper,[126] transition paths of this kind ultimately cannot address any underlying inefficiency or inequity.

Finally, in respect of the third point listed above, the Consultation Paper moves away from the exhaustive list of potential allocation options proposed in the Second Issues Paper. It instead proposes that the method for calculating the residual charge

124 Draft Proposed Guideline, clause 32(c).

125 Draft Proposed Guideline, clauses 54-66.

126 Green *et al*, *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015, pp.90-94

must be either 'historical anytime maximum demand'[127] or 'another method'.[128] In our opinion, this is a welcome change to the proposal.

We remain of the view that the proposed residual charge may be distortionary and be seen as unfair.

Overall, although the Consultation Paper makes some attempt to address the concerns raised in our previous report through changes to the proposed approach, the principal problems remain. We therefore remain of the view that the proposed residual charge on load could give rise to inefficient distortions and might, in some circumstances, be considered inequitable.

4.4 Summary

In our previous report, we concluded that the proposed charging methodology may not result in a more efficient allocation of sunk costs *after* investments had been made. Having reviewed the material in the Consultation Paper, we remain of the view that the AoB charge would not improve allocative efficiency, since:

- while any inefficient load shedding would cease in the near-term if the proposal was implemented, this would be due to the removal of the RCPD charge, not the introduction of the AoB charge, i.e., an LRMC charge would do the same;
- there were allocative inefficiencies arising from the HAMI-based parameter on the HVDC charge, but these have diminished significantly following the announcement of the SIMI-based parameter;

Although the revised proposal includes some welcome charges, we remain of the opinion that it may not result in a more efficient or fairer allocation of sunk investment costs.

- imposing a substantial amount of additional transmission charges on final load customers would be likely to result in a reduction in demand, which would give rise to an allocative efficiency loss; and
- any allocation of AoB charges to generators that is based on their average injections has the potential to distort their bidding conduct, compromising the efficiency of the wholesale dispatch process.

We also consider that the revised proposal would give rise to significant productive inefficiency from:

- the additional costs that would be incurred estimating private benefits and giving effect to the AoB charging methodology more generally; and
- the extra costs that would accompany the increase in lobbying and disputation that would be expected to follow the introduction of an AoB charge.

We also continue to believe that the proposed residual charge on load could give rise to distortions and might, in some circumstances, be considered unfair, since:

- there would still be some risk of customers inefficiently changing their conduct – particularly as the time approaches for the residual charge to be 'reset'; and

127 Draft Proposed Guideline, clause 33(a).

128 Draft Proposed Guideline, clause 33(b). We note that this clause is limited by clause 32(a), which states that the method for calculating the residual charge must 'use load to identify the designated transmission customers that must pay the residual charge, and the extent to which those customers must pay.'

- the significant wealth redistributions that would occur under the proposal might be viewed by some customers as inequitable and a form of 'hold-up'.

Finally, it is not altogether clear to us that Transpower would be able to feasibly implement various aspects of the Draft Guidelines. For example, it is directed to strike an appropriate balance between 'accuracy and simplicity' when applying AoB charges yet, for the reasons we have explained, the methodology itself arguably *cannot* be accurate, since it would not be cost-reflective. The clauses requiring Transpower to correct for 'anomalies' and levy 'broadly equivalent charges' on businesses in 'broadly equivalent circumstances' are also unhelpfully vague and it is far from clear whether they could be implemented effectively.

The overall conclusion that we reached in our previous report consequently remains the same. Namely, while the revised proposal includes some welcome charges, we remain of the opinion that the methodology still may not result in a more efficient (or fairer) allocation of sunk investment costs.

Table 4.1 provides a complete summary of all the points that we raised on the extent to which the proposed methodology would result in a more efficient allocation of sunk costs in our previous report, and whether they have been considered and addressed satisfactorily.

Table 4.1: Would there be a more efficient allocation of sunk costs?

Issues raised in previous report		Outcome
Changing the way in which sunk costs are allocated by implementing an AoB charging methodology may not improve allocative efficiency.	While any inefficient load shedding would cease in the near-term if the proposal was implemented, this would be due simply to the removal of the RCPD charge, not the introduction of the AoB charge.	Considered but unresolved
	There were allocative inefficiencies arising from the HAMI-based parameter on the HVDC charge, but these have diminished significantly following the announcement of the SIMI-based parameter.	Not considered
	Imposing a substantial amount of additional transmission charges on final load customers would be likely to result in a reduction in demand, which would give rise to an allocative efficiency loss.	Not considered[129]
	Levying AoB charges on generators may compromise the efficiency of the wholesale dispatch process.	Unresolved
	The earlier proposal to apply depreciated historical cost (DHC) charges to existing assets earmarked for AoB charges was unnecessary and would have resulted in an inefficient time profile of prices.	Resolved

129 Note that this point is considered by OGW in its report. However, as we explain below, its response does not address satisfactorily the underlying concern.

<table>
<tr><th colspan="2">Issues raised in previous report</th><th>Outcome</th></tr>
<tr><td rowspan="3">The AoB charging approach would be likely to give rise to significant additional costs, i.e., reduce productive inefficiency.</td><td>Additional costs would be incurred estimating private benefits, relative to the status quo.</td><td>Considered but unresolved[130]</td></tr>
<tr><td>Additional costs would be associated with the increase in lobbying and disputation that would be expected to follow the introduction of such a charge.</td><td>Not considered[131]</td></tr>
<tr><td>There would be ongoing disruptions associated with the application of the MBAM, applications for prudent discounts, and so on.</td><td>Considered and partly resolved[132]</td></tr>
<tr><td rowspan="3">The proposed residual charge on load could give rise to distortions and be considered unfair.</td><td>There would still be some risk of customers inefficiently changing their conduct – particularly in the lead ups to the residual charge being ‘reset’.</td><td>Not considered</td></tr>
<tr><td>The significant wealth redistributions that would occur under the proposal might be viewed by some customers as inequitable and a form of ‘hold-up’.</td><td>Considered and partly resolved[133]</td></tr>
<tr><td>It seemed neither necessary nor desirable to limit the potential residual charge allocation options that Transpower has as its disposal in the Guideline</td><td>Considered and partly resolved[134]</td></tr>
</table>

130 The changes do not address the basic problem that Transpower would face estimating private benefits over the 30- to 50-year (or thereabouts) lives of interconnection assets. There would also be no way for Transpower to efficiently ‘trade-off’ between ‘accuracy and simplicity’ when setting AoB charge since, for the reasons we have explained, the charge is not cost-reflective.

131 Note is considered by OGW in its report, but its response again does not assuage the problem.

132 The paper proposes not to extend the prudent discount policy to encompass the exit of load and to relegate the MBAM to an optional component of the methodology – both beneficial changes.

133 The Guideline provides some (albeit rather unclear) direction to Transpower to avoid ‘charging anomalies’ and to levy residual charges that “result in broadly equivalent charges to customers that are in broadly equivalent circumstances”. There is also a transition mechanism but, as we explain in Appendix A, there are problems with its specification in the current Draft Guidelines.

134 We note that Transpower’s discretion is not unfettered in this regard. For example, clause 32(a) states that the method for calculating the residual charge must ‘use load to identify the designated transmission customers that must pay the residual charge, and the extent to which those customers must pay.’

5. The Oakley Greenwood cost-benefit analysis

Oakley Greenwood undertook a cost benefit analysis (the 'OGW CBA'), which estimated that introducing the AoB charge proposed in the Second Issues Paper would yield a net benefit of $213.3m in present value terms. In our previous report, we observed that the OGW CBA rested upon three foundational assumptions that did not hold; namely:[135]

In our previous report, we observed that the OGW CBA rested upon three foundational assumptions that did not hold.

- that the AoB charge would provide an efficient *ex-ante* shadow price signal, when, for the reasons set out in section 3.2, it would not, and would instead risk compromising static and dynamic efficiency;
- that the reallocation of costs – and resultant wealth transfers – that would occur under the proposal would not give rise to any allocative efficiency loss through inefficient reductions in demand, when that is not realistic; and
- that the AoB charges that each customer would pay can be proxied by an estimate of the LRMC of transmission in each RCPD region, when they would instead each face a unique price that may be above or below that level.

We explained also why many of the other more specific elements of the modelling did not reflect the way the electricity system functions or how its participants make decisions.[136] We concluded that no weight could be placed on the resulting estimate of net benefits. OGW was asked to consider our observations – and those of other submitters – and to change its CBA, where necessary. It concluded that:

- the concerns raised by submitters – including ourselves – were either invalid, or had no material bearing upon the overall results; and
- there was consequently no need to make any revisions of substance to its CBA, leaving its estimate of net benefits largely unchanged ($203m vs $213.3m).[137]

Below, we consider the responses provided by OGW to the concerns that we raised in our last report and whether they cause us to revise our previous conclusions as to the efficacy of the CBA. Note that we have not undertaken a comprehensive review of OGW's replies to the points raised by other submitters.

5.1 Foundational assumptions

The OGW report provides a variety of responses to the concerns that we expressed regarding the three foundational assumptions that underpinned its analysis. We examine these in turn below.

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135 Axiom July 2016 Report, p.53.

136 *op cit.*, pp.54-60.

137 The $10.3m reduction from the previous version is attributable entirely to the removal of some of the proposed changes to the prudent discount policy (PDP). Following the advice received in submissions on the Second Issues Paper (including our previous report), the Authority concluded that this proposal would not be beneficial. It therefore seems counterintuitive that its removal from the revised proposal would cause a *reduction* in the perceived net benefits on offer.

5.1.1 The AoB charge would not provide an efficient price signal

OGW states that the concerns raised about the assumed efficiency of the AoB charge hinge ultimately on the extent to which those charges are likely to reflect the LRMC of transmission.[138] The clear implication is that, if AoB charges *did* reflect LRMC in each RCPD region, then OGW would consider those charges to be efficient. To that end, OGW claims the LRMC charge it has modelled *does* represent a reasonable proxy for the AoB charges that individual customers would be charged for specific assets. It states 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.'* [our emphasis] (p.6)

OGW implies that regional LRMC charges would be efficient, and states that they provide a reasonable proxy for AoB charges.

> *'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.'* [our emphasis] (p.17)

> *'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.'* [our emphasis] (p.19)

Three things are worth noting in this respect. First, if the efficiency of the AoB charge is defined primarily by the extent to which it mimics a regional LRMC charge, this begs the question: why not simply introduce a regional LRMC charge? Presumably the 'real thing' would be superior to a 'reasonable proxy'. It implies also that, even if the estimated $213m NPV net benefit of introducing a regional LRMC charge was robust (which it is not), then the net benefit of introducing an AoB charge – an imperfect proxy – would be a lesser amount.

[138] OGW Response to Issues, p.6.

Regional LRMC charges do not provide a reasonable proxy for individual customers' AoB charges.

Second, it is not correct to contend that regional LRMC charges are synonymous with the AoB charges that individual customers would face under the proposed methodology. As we have emphasised at length throughout this report and our last, individual customers' AoB charges would not necessarily reflect *any* measure of LRMC, much less regional LRMC.

Instead, the individual 'shadow-price' signals that customers perceived before an investment is made – and the costs that they would be allocated afterwards – could be well above or below the levels that would be implied by a regional LRMC charge (or any other measure of LRMC). OGW concedes as much when it highlights the important differences between the two charging approaches:

> *'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.'* [our emphasis] (p.7)

> *'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****'* [our emphasis] (p.19)

OGW's contention that the AoB charge would provide an efficient price signal assumes that the MBAM is a part of the methodology.

The third important thing to note is that an important reason why OGW considered that the AoB charge would provide an efficient 'marginal price signal' (which we presume to mean a price signal that reflects the LRMC of transmission) was the inclusion of the MBAM. Specifically, OGW concluded that one of the most important advantages of the AoB charge over the deeper connection-based charge was its structure; which meant that:[139]

> *'...the customer not only sees a total price that equates to the benefits they receive, but also a cost-reflective marginal price signal. In comparison, the deeper connection-based charge is assumed to simply allocate the full cost of an asset according to use, therefore, it does not send a truly marginal price signal. The lack of a marginal price signal is likely to lead to inefficient outcomes.'*

The core proposition in this statement – namely, that the MBAM would provide an efficient marginal price signal – is incorrect, for the reasons set out in our previous report (which we do not repeat here).[140] It is also incorrect to imply that the combination of AoB charges and a MGAM would yield a price signal that reflected the *regional LRMC* of transmission – which is what OGW has modelled. However, assuming for the sake of argument that OGW *was* correct then, based on its own

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139 Oakley Greenwood, *Cost Benefit Analysis of Transmission Pricing Options, prepared for: NZ Electricity Authority*, 11 May 2016, p.12.

140 *See:* Axiom July 2016 Report, pp.20-23.

logic, removing the MGAM component from the AoB charging framework would result in an inefficient charge.

The MBAM is not a mandatory part of the TPM and it is unlikely that Transpower would choose to implement it.

This is relevant because, as we explained in section 3.2.4, the MBAM has been relegated from a mandatory component of the proposal to a mere option that Transpower might choose to pursue. In other words, it would only feature in the TPM if Transpower was inclined to implement the mechanism. OGW's solution to this problem is straightforward. It simply asserts that Transpower *would* exercise the option of introducing the MBAM 'on the balance of probabilities':[141]

> *'Our position is that given the increasing returns to scale from making lumpy transmission investments, Transpower is likely to consider an additional marginal price signal both practicable and consistent with the requirements of clause 12.89 of the Code, hence, on the balance of probabilities, it will be introduced. As such, we do not consider there to be any reason to adjust our original CBA.'*

This conclusion does not seem plausible. In our report in response to the Second Issues Paper we highlighted substantial flaws in both the theory underpinning the MBAM and the disruptive influence that it would have on Transpower's investment processes, in practice.[142] Transpower reiterated these concerns in its own submission[143] - concerns which the Authority acknowledged and responded to by relegating the mechanism to an option. Against this background, the prospect of Transpower implementing a MBAM would seem to be slim, at best.

We remain of the view that OGW's first foundational assumption does not hold.

In summary, OGW is incorrect to contend that a combination of AoB charges and a MBAM would yield a price equal to the *regional LRMC* of transmission – and that it would be an efficient charge. There is also no basis for it to assume that Transpower would introduce a MBAM. Based on OGW's logic, this would render the price signals that would be delivered by any AoB charge inefficient, because they would not reflect LRMC.[144] We therefore remain of the view that the first foundational assumption underpinning the OGW CBA does not hold.

5.1.2 There would be an allocative efficiency loss

A further foundational problem that we highlighted with OGW's CBA was its unrealistic assumption that the large increase in transmission costs to load customers would not result in any inefficient reductions in demand. OGW responds to that criticism by suggesting that it rests on the presumption that EDBs would act irrationally by passing-through higher transmission charges in ways that were economically inefficient.

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141 OGW Impact of Changes, p.14.

142 *See:* Axiom July 2016 Report, pp.20-23.

143 Transpower, *Transpower Submission: Transmission Pricing Methodology, 2nd Issues and Proposals Paper*, 26 July 2016, p.33.

144 As we noted above, this would actually be the case irrespective of whether a MBAM was introduced by Transpower.

OGW contends that our criticism assumes that EDBs would act irrationally.

OGW contends that it is more realistic to expect that electricity distribution businesses (EDBs) would pass-through fixed transmission charges as *fixed* distribution charges. It suggests that, on that basis, there would be neither any response from final load customers nor any deadweight loss:[145]

> *'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.'*

For the chain of events postulated by OGW to occur and no deadweight loss to arise, three conditions would need to hold. First, EDBs would need to be permitted to pass-on the additional transmission charges as fixed distribution charges. Second, all twenty-nine EDBs would have to be inclined to do so. And, finally, consumers would have to have no reaction at all to those increased fixed charges, i.e., they would have to continue to consume the same amounts of electricity. In our opinion, the probability of all three of these conditions holding is virtually zero.

EDBs may not be allowed to pass-through the additional transmission charges as fixed charges.

It is far from clear that it would even be permissible for EDBs to pass-through the additional transmission charges as fixed distribution charges. The Low Fixed Charge (LFC) regulations require EDBs to offer a price option which has a fixed charge of not more than 15c/day and a variable component set so that the average consumer (as defined in the regulations), pays no more per year on the low fixed charge option than on any other pricing structure. These regulations would be likely to prevent 100% pass-through in the form of fixed charges.

We note that the Authority has expressed the view that the LFC regulations do not prevent the use of 'variable charges' based on a consumer's capacity, i.e., the size of her connection.[146] In other words, the suggestion is that a 'capacity charge' can be construed as a fixed charge under the regulations. So, could additional transmission charges be passed-on as capacity charges? In our view, that is unlikely. The Authority's conclusion is based on a very narrow reading of the regulations, which define fixed and variable charges as follows:

- a fixed charge is a charge that is levied for each consumer connection to a distribution network that is in currency per time period, e.g., cents per day, dollars per month, etc.; and

145 OGW Response to Issues, p.37.

146 Electricity Authority, *Implications of evolving technologies for pricing of distribution services, Consultation Paper*, 3 November 2015, p.72.

- a variable charge is a charge that varies according to the amount of electricity consumed, e.g., cents per kWh.

In other words, the Authority has reasoned that because a capacity charge would not be measured 'per time period' – i.e., it would be based on kWs – it does not sit within the definition of fixed charge and must therefore be 'variable'. However, this conclusion does not follow. The obvious problem with this logic is that a capacity charge does not conform with the regulations' definition of a variable charge *either*, because it would not vary with the amount of electricity consumed. Given that it must be one or the other – which is more likely?

In our opinion, the answer seems clear. Variable charges vary with the level of usage and fixed charges do not. A capacity charge is therefore an example of the latter. Indeed, if a capacity charge is not a fixed charge, then it is not clear to us what *would* meet the definition. It would therefore be a very bold move for an EDB to attempt to pass-through the additional transmission charges as capacity charges under the guise that they are 'variable charges', despite the Authority's recent reassurances.[147]

EDBs may not be inclined to pass-through the additional transmission charges as fixed charges.

Even if EDBs could somehow circumvent the apparent intent of the LFC regulations, it would involve a dramatic shift away from their current charging practices. As the Authority highlighted throughout its review of EDBs' pricing, at present, most businesses employ volumetric charges as their primary pricing approach. We agree that a move away from predominantly volumetric charging could well be beneficial and 'more consistent with economic theory', as OGW implies. We also do not dispute that it could make commercial sense.

However, we very much doubt that all twenty-nine businesses would depart *en-masse* from their entrenched pricing approaches when they came to pass-through the new transmission charges (if the LFC regulations allowed it). In our opinion, an altogether more reasonable assumption would be that at least some of any increase in transmission costs that flowed-through to final load customers would manifest in the form of variable charges, e.g., volumetric tariffs. It is therefore reasonable to expect that there would be some level of demand response.

Customers might respond to additional charges by reducing demand.

Finally, even if one could plausibly stretch the definition of variable charges to encompass a capacity charge, and assume credibly that all EDBs would pass-through the incremental transmission charges in this way, it does not follow that consumers would not respond. If customers could reduce their transmission charges by reducing the size of their connections, then some might do so – even if it meant curtailing their peak demand to accommodate their smaller links. Indeed, if there

147 We recognise that, strictly speaking, EDBs are permitted to do anything that is not expressly prohibited by law (this is the so-called 'third source' of law in jurisprudence). Therefore, EDBs could conceivably state that capacity charges are not fixed charges under the definition in the regulations and are therefore permissible – even though they do not conform with the definition of variable charges either. However, as we suggest above, this would be a brave move given that capacity charges would seem to clearly fit more comfortably within the ordinary definition of fixed charges. Indeed, this might simply prompt the Ministry of Business, Innovation and Employment to clarify the definitions in the regulations to prevent EDBs from doing so.

was no prospect of customers avoiding the charge by engaging in such behaviour then it would seem almost untenable to suggest that it is a 'variable charge' in any meaningful sense.

We remain of the view that OGW's second foundational assumption does not hold.

For those reasons, we remain of the view that it is not tenable to suggest that the large wealth transfers that would be precipitated by the proposal would not prompt any demand-side reaction at all from load customers. In our opinion, a deadweight loss is inevitable – and the extent of that allocative inefficiency could be considerable. We are therefore still of the opinion that the second foundational assumption underpinning the OGW CBA does not hold.

5.1.3 The CBA does not model an AoB charge

OGW contends that it is not possible to model the AoB charge without significant simplifying assumptions.

One of the most significant concerns raised by both ourselves and others with respect to OGW's CBA was that it did not actually model the AoB charge that has been proposed but, rather, a regional LRMC charge. In its report in response to issues raised with its CBA, OGW acknowledges that this is indeed what it has done. Its response to this criticism is threefold. Firstly, it contends that it is *not possible* to model the AoB charge with any accuracy, giving rise to the need to make significant simplifying assumptions:

> *'…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** … Modelling of complex decisions by multiple parties facing uncertainty over an extended period **can only ever be an approximation**.'* [our emphasis] (p.16)

> *'…the model presents a **simplified picture of the real world** so as to estimate the benefits of the proposal it is modelling.'* [our emphasis] (p.17)

OGW claims that a regional LRMC charge is a reasonable proxy for an AoB charge.

Secondly, as we noted in section 5.1.1, OGW claims that an LRMC charge represents a *reasonable proxy* for the AoB charge that has been proposed and, importantly, for the prices that individual customers would be charged for specific assets. And thirdly, OGW argues that no evidence has been presented to suggest that using an LRMC-based proxy of this kind would 'bias' its results:

> *'…no evidence has been presented to suggest that LRMC based analysis **would be biased one way or another**.'* [our emphasis] (p.17)

OGW contends that no evidence has been provided to suggest that using an LRMC-based proxy would 'bias' its results.

> *'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.'* [our emphasis] (p.19)

In our opinion, none of these responses are reasonable. Firstly, while we agree entirely that any exercise of this kind must necessarily involve simplifying assumptions, there is no doubt that the modelling could quite easily have borne a much closer resemblance to the AoB charge that was (and is) being proposed. We note, for example, that:

The modelling could easily have resembled more closely the AoB charge actually being proposed.

- in its both its Revised Issues Paper and its Second Issues Paper, the Authority modelled indicative transmission charges (including AoB charges) – albeit only for a single year – based on various assumptions about the distribution of private benefits amongst different customers; and
- Scientia Consulting modelled the HVDC charges that individual South Island generators would face under the application of both a MWh and diluted HAMI parameter, which then formed a core part of a CBA undertaken by Transpower during its operational review (see: here and here).

There is therefore no compelling reason why OGW could not have undertaken a similar, more sophisticated analysis – particularly given its expertise in this area. To be sure, this may have made the analysis more complex and less transparent – particularly if dispatch modelling was used. However, in our opinion, that would be a small price to pay for a CBA that bore more than a token resemblance to the methodology that was being proposed.

A regional LRMC charge is not a reasonable proxy for an AoB charge.

Secondly, as we explained in section 5.1.1, a regional LRMC charge is *not* a reasonable proxy for the AoB charges that individual customers would face – a point that OGW effectively concedes.[148] It follows there is no basis for OGW to have any confidence that the hypothetical future 'build orders' that it has modelled would bear any resemblance to those that would actually eventuate if the proposal was implemented.

There is no need to show that OGW's approach is 'biased' – it is demonstrably unsound.

Thirdly, it is not reasonable to deflect these criticisms by contending that no evidence has been presented to suggest that the LRMC-based analysis is biased one way or the other. In our view, it has been demonstrated clearly – and even acknowledged by OGW – that the modelling does not reflect the Authority's proposal. It follows that the estimate of net benefits cannot be meaningful. The mere fact that the estimate exists does not bestow upon it any special status that requires submitters to prove that the 'real' number is higher or lower. If the number is not robust – which, in our view, it is not – then it is not relevant.

Moreover, assuming such evidence was required, it is not obvious how it could be produced. As we noted above, much of OGW's response is devoted to explaining why it was not feasible to model the AoB charge with any accuracy. If that were true (which, as we noted above, it arguably is not), then how could one establish bias? It is not reasonable for OGW to defend its decision to model an LRMC charge by saying that it was too difficult to replicate the actual AoB charge, and then expect

148 OGW Response to Issues, pp.7-19.

submitters to do *precisely that* before it is prepared to concede that there is a problem with its results.[149]

For those reasons, nothing in OGW's report has caused us to change our opinion that the AoB charges that each market participant would pay cannot reasonably be proxied by an estimate of the LRMC of transmission in each RCPD region. We therefore remain of the view that the third foundational assumption underpinning the OGW CBA does not hold.

5.2 More specific assumptions and modelling elements

OGW provides responses to a small number of the concerns that we expressed in relation to the more specific assumptions and approaches underpinning its modelling. We consider those responses in turn below. We then highlight the larger set of problems that were identified in our report, but are not addressed by in any way in OGW's report.

5.2.1 Issues addressed in OGW's report

In our previous report, we observed that the modelling of generator entry within the CBA – which assumed that decisions were made solely based on the average total cost (ATC) of a unit of generation - did not reflect how those choices are made in practice. OGW agreed with our assessment:[150]

The unrealistic assumption as to how new generation investment decisions are made remains a problem.

> *'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, having acknowledging the unrealistic nature of its modelling of entry decisions, OGW then contends that this shortcoming is not critical:[151]

> *'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.'*

This does not represent a satisfactory response to the concerns that were raised. At no stage has OGW addressed the point that generator's entry decisions – and, in

149 To put it colloquially, the same defence could be offered for a methodology in which an estimate had been derived by throwing a dart at a board.

150 OGW Response to Issues, p.16.

151 OGW Response to Issues, p.17.

turn, the 'build-order' that is so central to its estimate of benefits – would not be determined by the ATC of a unit of generation. The passage above also reflects again the mistaken belief that AoB charges would reflect the LRMC of transmission when, for the reasons we have reiterated throughout this report, they would not.[152]

Our previous report also questioned the validity of the assumed increase in the uptake of embedded diesel generation from customers seeking to avoid RCPD charges if the status quo remains in place. We understood the current level of installed embedded diesel generation to be around 12MW. The CBA assumed that the amount of such generation would increase to around 500MW under the status quo which, in our assessment, did not seem feasible. OGW responds by stating that:[153]

> *'…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.'*

The assumed level of new investment in embedded diesel generation remains unreasonable.

In our view, whether the assumed increase in uptake is 490MW or 400MW is irrelevant. In our opinion, neither figure is credible. It is not reasonable to conclude that all other forms of cheaper distributed generation have now been exhausted – no evidence at all is provided to support this proposition. And nor is it reasonable to suggest that the forecast could be valid if the economics of investing in diesel generation could improve in the future. One could just as easily say the opposite, i.e., that the environment for investments could become *less* attractive in the future.

Problems remain with the way that wind plants have been modelled.

We also highlighted that no adjustment was made in the modelling to account for the intermittency of wind generation. The results instead relied on an assumption that wind farms can be relied upon to operate at 100 per cent capacity during peak demand. OGW concedes that it did indeed neglect to discount the capacity of wind plants to reflect their reliability. It explained that this was 'an oversight'.[154] However, it then contends that:[155]

> *'…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*

152 Indeed, the 'much deeper problem' to which OGW refers in the last sentence of this passage is precisely the problem that we have been stressing throughout this report and our last. The price signals that would be provided by the proposed AoB charge would not necessarily reflect the LRMC of transmission, and so there is no reason to think that the generation and transmission investments that would result from those price signals would reflect LRMC either.

153 OGW Response to Issues, p.12.

154 OGW Response to Issues, p.19.

155 *Ibid.*

> *proposal and the status quo cases), hence diminishing its effects in the overall result.'*

This is essentially the same response that was offered when Transpower sought to clarify the basis of this assumption during the consultation on the Second Issues Paper.[156] As we stated at that time,[157] it does not represent a robust answer. Even if OGW's contention is correct,[158] if critical assumptions that do not reflect the power system that is supposedly being modelled do not have a material effect upon the estimates of benefits, then that is symptomatic of grave problems with the CBA. Almost by definition, the results *should not* be immune to such large errors.

Finally, our previous report questioned the CBA's assumption that the proposed reforms would avoid costs arising from disputes that would occur under the status quo.[159] We explained why we considered the proposal would almost certainly lead to more disputation and a significant increase in administrative costs.[160] In its response, OGW claims that any assessment of costs is likely to be 'quite subjective'[161] in nature, and that there is no reason to think that the proposal would entail any significant additional costs:

The CBA continues to underestimate the additional costs that the proposal would create.

> *'…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.'*

In our opinion, these contentions are not credible. As we explained in section 4.2, if the reforms went ahead, both Transpower and the Authority would face substantial additional costs designing the various aspects of the AoB charging framework. Industry participants would also face additional costs engaging with these parties throughout the lengthy consultation process that would inevitably ensue. There may also be costs associated with legal proceedings if any of those decisions were subjected to a judicial review – a regular feature of past processes.

Moreover, even after the methodology had 'bedded-in', the scope for ongoing disputes would ramp-up considerably relative to the status quo, as participants

156 Email response from Electricity Authority to questions from Transpower, 7 July 2016.

157 Axiom July 2016 Report, p.58.

158 In our opinion, it is not obvious that the error would have an equivalent impact upon all of the modelling scenarios – the effects could vary significantly across the different 'states of the world'

159 Axiom July 2016 Report, pp.59-60.

160 *Ibid.*

161 OGW Response to Issues, p.40.

argued with Transpower about the benefits that they derived from new investments. Further costs would also be incurred if Transpower opted to implement a MBAM – a step which, remember, OGW considers that it will take 'on the balance of probabilities'[162] (an assessment with which we disagree). The proposal would therefore involve much higher costs than retaining the status quo.

5.2.2 Other errors remain unacknowledged

A significant number of the problems that we identified with OGW's CBA in our previous report do not feature in its latest report (or are identified, but not discussed in any way). Perhaps the two most perplexing omissions are the following:

OGW does not address two errors that are critical to its net benefit estimate.

- In calculating the benefits of deterring investment in inefficient alternatives to networks, the model assigns a 100% weight to the 'Huntly Stays' scenario, when the 'Huntly Leaves' scenario is afforded equal weight everywhere else in the CBA.[163] HoustonKemp has estimated that addressing this inconsistency would reduce OGW's estimated net benefit by almost $85m (around 42% of the estimated $203m net benefit).[164]
- The benefits from removing the SIMI charge have been assessed over a 30-year timeframe, whereas a 20-year timeframe is used for all other elements. OGW does not provide a satisfactory explanation for this asymmetric treatment[165] or, more generally, for the model's failure to deal appropriately with the types of 'end-effects' that this arbitrary adjustment is ostensibly intended to fix. HoustonKemp has estimated that, if the effects of removing the HVDC charge are calculated over a 20-year period, the result is a net cost of $101.9 million (a net reduction in overall net benefits of around $115m, or 57%).[166]

In other words, simply addressing these two apparent inconsistencies within OGW's modelling using its own methodology – and leaving everything else unchanged – would reduce the estimated net benefit from $203m to less than $3m – or **by 99%**. To be clear, we are not suggesting that this would be the appropriate approach since, as we noted above, this striking result is largely symptomatic of

162 OGW Impact of Changes, p.14.

163 Axiom July 2016 Report, p.57.

164 HoustonKemp, *Review of the cost benefit analysis of the proposed TPM guidelines, A report for Trustpower*, 26 July 2016, p.56.

165 In its previous report, OGW stated that: '*the 20-year timeframe was unduly influenced by specific timing related issues that affected when generation assets were expected to be developed in the model, which skewed the results when undertaken over this shorter evaluation period*' (Oakley Greenwood, *Cost Benefit Analysis of Transmission Pricing Options, prepared for: NZ Electricity Authority*, 11 May 2016, p.55). It is quite common for large, lumpy cash flows arising at the end of a modelling horizon to have a substantial influence on the results. However, there are well-established approaches to dealing with end-effects in this type of modelling. Extending the modelling period for a single series of benefits is not among them, as we explained in our previous report, *see*: Axiom July 2016 Report, p.84.

166 HoustonKemp, *Review of the cost benefit analysis of the proposed TPM guidelines, A report for Trustpower*, 26 July 2016, p.63.

deeper problems with the modelling.[167] Nevertheless, it is surprising that these points have not prompted at least some form of response, given their gravity.

Other significant problems that we raised in our previous report, but which were not addressed in any way include the following:

Other significant problems also remain unacknowledged.

- The modelling does not account for the constraints associated with hydro-electric plants (e.g., annual inflows, energy storage constraints, etc.).[168] These are clearly highly relevant considerations in a hydro-dominated system and undermine further the reliability of the estimate of benefits derived from the model's projected planning schedule.
- The modelling assumes that a robust 'combined' LRMC can be obtained by adding an estimate of the LRMC of transmission (in $/MWh) to the ATC of generation (in $/MWh), which is not the case.[169]
- The calculation of benefits assumes that each plant generates as per its assumed capacity factor, i.e., once a generator has been constructed, it is presumed to have a fixed future level of output and costs, regardless of energy demand which, once more, is not a realistic assumption.[170]

It is not obvious why these problems have not been considered.

It is again not obvious why these problems were not addressed in any way in OGW's report. In our opinion, any of the problems described above has the potential to compromise the results of the CBA and render it unfit for its intended purpose. They should therefore have warranted a response that explained why the Authority could continue to rely on the estimate of net benefits, despite those apparent shortcomings.

5.3 Summary

OGW's responses to the points that we raised about its modelling in our previous paper do not assuage those concerns. Rather, for the most past, they simply confirm the existence of the serious problems that we originally identified. For example, OGW acknowledges that:

- it has not modelled an AoB charge but has instead modelled a charge where market participants would face a price equal to an estimate of the LRMC of transmission in each RCPD region – an entirely different approach;
- its modelling of generator entry does not reflect the way in which those decisions are made in practice, i.e., they are not based solely on the ATC of a unit of generation; and

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167 Including, for example, the failure to properly employ terminal values to deal with the problems arising from lumpy cashflows described above.

168 OGW note that we raised this problem in our report (see: OGW Response to Issues, p.20), but then do not address it in any way.

169 Axiom July 2016 Report, p.56.

170 Axiom July 2016 Report, p.57. OGW once again notes that we raised this problem in our report (see: OGW Response to Issues, p.20), but does not attempt to respond to the concern.

- no adjustment was made in the modelling to account for the intermittency of wind generation, i.e., the assumption is made that wind farms can be relied upon during peak demand to operate at 100 per cent capacity.

Although OGW concedes that these are indeed features of its modelling, it suggests that the problems are immaterial. We disagree; particularly with the proposition that a regional LRMC charge forms a reasonable proxy for an AoB charge. We also do not accept OGW's contentions that:

- EDBs would be likely to pass-through any increases in transmission charges entirely in the form of fixed distribution charges, resulting in no reduction in demand, since this would require an implausible series of assumptions to hold;
- it is reasonable to anticipate that the amount of embedded diesel generation would increase enormously to 500MW if the status quo was retained, because no evidence has been provided to support this proposition; and
- there is no reason to think that the proposal would entail any significant increase in the level of dispute or administrative costs relative to the status quo, since there is little doubt that both these things would happen.

We also identified a significant number of other problems in our previous report that have the potential to compromise the results of the CBA and render it unfit for its intended purpose. Yet, rather puzzlingly, these have not prompted any reply in OGW's latest report. These problems include the following:

- in calculating the benefits of deterring investment in inefficient alternatives to networks, the model assigns a 100% weight to the 'Huntly Stays' scenario – this appears to simply be a mistake, and inflates the benefits estimate by $85m;[171]
- the modelling does not deal appropriately with 'end values', which causes OGW to make an arbitrary adjustment to its assessment of the SIMI charge (measuring it over 30-years instead of 20-years), which increases the benefits by $115m;[172]
- the modelling does not account for the constraints associated with hydro-electric plants (e.g., annual inflows, energy storage constraints, etc.), which clearly are highly relevant considerations in a hydro-dominated system;
- the modelling assumes that a robust 'combined' LRMC can be obtained by adding an estimate of the LRMC of transmission (in $/MWh) to the ATC of generation (in $/MWh), which is not the case; and
- the calculation of benefits assumes that each plant generates as per its assumed capacity factor, i.e., once a generator has been constructed, it is presumed to have a fixed future level of output and costs, regardless of energy demand.

171 HoustonKemp, *Review of the cost benefit analysis of the proposed TPM guidelines, A report for Trustpower*, 26 July 2016, p.56.

172 *op cit.*, p.63.

We remain of the opinion that no weight can reasonably be placed on OGW's estimate of net benefits.

Put simply, the CBA modelling does not reflect accurately the proposed AoB charge methodology (including its inefficiencies), the way in which the electricity system functions or the way its participants make decisions. We therefore remain of the opinion that no weight can reasonably be placed on the resulting estimate of net benefits.

Table 5.1 provides a summary of all the points that we raised in relation to the OGW CBA in our previous report, and whether they have been considered and addressed satisfactorily.

Table 5.1: Oakley Greenwood cost-benefit analysis

Issues raised in previous report		Outcome
Foundational assumptions	The CBA assumes that the AoB charge would provide an efficient *ex-ante* shadow price signal, when, for the reasons set out above, it would not, and would instead risk compromising static and dynamic efficiency.	Considered but unresolved
	The modelling presumes that the reallocation of costs – and resultant wealth transfers – that would occur under the proposal would not give rise to any allocative efficiency loss through inefficient reductions in demand, when that is simply not realistic.	Considered but unresolved
	The CBA assumes that the AoB charges that each market participant would pay can be proxied by an estimate of the LRMC of transmission in each RCPD region, when each customer would instead face a unique price that may be above or below LRMC.	Considered but unresolved
More specific assumptions and modelling elements	In calculating the benefits of deterring investment in inefficient alternatives to networks, the model assigns 100% weight to the 'Huntly Stay's scenario – this appears to simply be a mistake, and inflates the benefits estimate by $85m.	Not considered
	The modelling does not deal appropriately with 'end values', which causes OGW to make an arbitrary adjustment to its assessment of the SIMI charge (measuring it over 30-years instead of 20-years), inflating the benefits estimate by $115m.	Not considered
	The CBA assumes that new generation entry decisions would be based solely on the average total cost of a new unit of generation.	Considered but unresolved
	The modelling presumes that new investments are determined only by maximum demand, and that capacity factors are fixed for all such investments, which is not realistic.	Not considered
	The CBA assumes incorrectly that wind farms can be relied upon to operate at a 100% capacity factor during peak periods.	Considered but unresolved
	The CBA does not take into consideration any of the constraints related to hydro plants, e.g., annual inflows, etc.	Not considered
	The modelling assumes incorrectly that a robust 'combined' LRMC can be obtained by adding an estimate of the regional LRMC of transmission (in $/MWh) to the ATC of generation (in $/MWh).	Not considered
	The CBA assumes there would be an implausible increase in embedded diesel generation (to 500MW) if the status quo is retained.	Considered but unresolved
	The modelling assumes that there would be no significant increase in administrative costs if the proposal was implemented.	Considered but unresolved

6. Conclusion

In this report, we have considered whether the material set out in the Consultation Paper and the accompanying documents causes us to change any of the key conclusions we reached in our previous report in response to the Second Issues Paper. It does not. We remain of the opinion that:

All the conclusions set out in our previous report remain valid.

- the combination of nodal prices, AoB charges and grid support contracts would not provide customers with an efficient *ex-ante* price signal of Transpower's future investment costs, and an *explicit ex-ante* price signal of some kind is required to elicit efficient outcomes, such as an LRMC charge;
- there is no reason to be confident that allocating the costs of investments after they have been sunk via an AoB charge would promote static efficiency or be more equitable overall, yet there is good reason to expect the proposal would result in more disputes and higher administrative costs; and
- the OGW CBA is not fit for its intended purpose, does not provide a robust indication of the likely impacts of the proposal and so cannot reasonably be relied upon to support the methodology.

We consequently continue to hold the view that the proposed methodology does not represent a clear improvement upon either the status quo, or alternative approaches in which LRMC charges are a core component, and not just a discretionary 'additional component'. It could instead reduce efficiency, overall.

Appendix A Problems with the drafting of the transition mechanism

The Draft Guidelines provide for a price cap on transmission charges to EDBs and direct-connect customers. The *intention* of the cap appears to be to reduce the initial wealth transfers/price shocks arising from application of the AoB and residual charges to certain existing assets. However, the way the mechanism is specified in the Draft Guidelines means it may not have this effect in practice. It is also likely to prove unworkable.

A.1 The non-transmission components of the base value may increase faster than the CPI

The starting point for the proposed price cap is a 'base value', specified as follows:[173]

- for an EDB, the estimated total of the electricity bills (including all charges in respect of transmission, distribution, energy, levies, and taxes) of all the EDB's customers in the 2019/20 pricing year, plus inflation (CPI); and
- for a direct-connect consumer, the consumer's estimated total electricity bill (including all charges in respect of transmission, distribution, energy, levies, and taxes) for the 2019/20 pricing year, plus inflation (CPI).

The Draft Guidelines then state that the cap must be set:[174]

- for an EDB, at 103.5% of the EDB's base value; and
- subject to certain exceptions, for a direct-connect consumer, at 103.5% of the consumer's base value.

In other words, if a direct-connect customer's electricity bill is $100 in the 2019/20 pricing year (using a round number) and the CPI was 0% (to keep things simple), then the Draft Guidelines appear to be saying that Transpower would have to set its transmission charges for 2020/21 at levels such that the customer's total electricity bill was no more than $103.50, i.e., the base value for 2020/21 (103.5% of $100).

So, if all the other components of the base value remained the same (consistent with the 0% movement in the CPI) from 2019/20 to 2020/21 (i.e., energy prices, etc.), the most by which Transpower could increase its charges to that customer would be $3.50 (assuming it had not introduced any 'additional TPM components' – a possibility we explore below). Of course, the problem is that the movements in the prices of the other components of the base value may not track the CPI.

For example, if 2020/21 is a dry-year and 2019/20 is not, then the energy price component of the customer's bill may increase sharply. For example, even if its transmission charge did not change, the customer's total estimated bill for 2020/21 could be, say, $105 – due purely to the uplift in energy prices. In these

173 Draft Guidelines, clause 55.

174 Draft Guidelines, clause 56.

circumstances, Transpower would need to *reduce* its charges by $1.50 to comply with the cap, i.e., to limit the customer's total estimated bill at $103.50.

The Draft Guidelines provide *some* protection to Transpower to guard against these circumstances. For example, it includes a provision that states that Transpower must be able to recover its total revenue requirement and, if the application of the cap prevents that, all caps must be increased proportionally so that Transpower *can* recover its total revenue allowance.[175] However, it may still find itself in circumstances where it must reduce its charges to individual customers (which do not compromise its ability to recover its revenue requirement overall) for reasons beyond its control, e.g., changes in local distribution prices, energy prices, etc.

Moreover, there are no protections at all for the *customers* the cap is intended to insulate if the *opposite* scenario arises. Returning to our previous example – imagine instead that 2019/20 is a dry-year and 2020/21 is not, and that the energy price component of the customer's bill *drops* sharply. This might enable Transpower to increase its transmission charges substantially to certain customers (namely, those that the cap is presumably intended to shield) without violating the overall constraint, or its revenue requirement.

In other words, unless the non-transmission components of the base value move perfectly in sync with the CPI, Transpower may find:

- that it must reduce its transmission charges to certain customers to comply with the cap, i.e., if the other components of the base value – such as energy prices or local distribution charges – increase by more than CPI; or
- that it can increase its charges substantially to certain customer without violating the cap, i.e., if the rate of change in the other components of the base value is less than the CPI.

In our opinion, given that there is no guarantee that the other components of the base value would track the CPI – especially energy values – the proposed transition mechanisms may prove to be unworkable in its current form. In our opinion, the most appropriate solution to this problem would be to base any price cap solely on *transmission* charges, rather that total electricity charges.

A.2 If Transpower introduces 'additional TPM components' the cap would become less meaningful

The second potential problem with the proposed transition mechanism stems from the specification of the so-called 'net charge'. The net charge for a year is defined in the Draft Guideline as:[176]

175 Draft Guidelines, clause 64.

176 Draft Guidelines, clause 57.

- for an EDB, the sum of the estimated electricity bills of all the EDB's customers for the year, including all charges in respect of transmission, distribution, energy, levies, and taxes; and
- for a direct-connect consumer, the consumer's estimated electricity bill for the year, including all charges in respect of transmission, distribution, energy, levies and taxes; *less*
- the amount payable by the EDB or direct-connect consumer for the year in question in respect of any of the *additional TPM components* that Transpower has introduced, such as an LRMC charge, or if it has extended the coverage of the AoB charge to encompass more past investments.

The Draft Guidelines then specify that the net charge cannot exceed the amount of the cap which, as we noted above, must be set at 103.5% of an EDB's or a direct-connect customer's base value (with certain exceptions for the latter). To illustrate how this would work, suppose again that a direct-connect customer's electricity bill is $100 in the 2019/20 pricing year and the CPI was 0%. The Draft Guidelines would require Transpower to set its transmission charges for 2020/21 so that the customer's *net value* was no more than $103.50, i.e., the base value (103.5% of $100).

If Transpower had not introduced any of the additional components listed in the Draft Guidelines – e.g., an LRMC charge – then the example is the same as in section A.1 above. That is, if all the other components of the 'base value' remain unchanged (which, as we explained above, may not be the case), the most by which it could increase its 2020/21 charges would be by $3.50 – otherwise the 'net value' ($103.50 *less* a CPI of zero) would be greater than the base value ($103.50).

But now suppose instead that Transpower *does* introduce additional TPM components, e.g., extends the application of the AoB charge to include more past assets, and/or introduces an LRMC charge. And imagine that it expects to recover $20 in charges from the customer through those charges in 2020/21. The 'net value' would then be $20 lower, i.e., assuming all the components of the base value had remained unchanged it would be equal to $100 *less* $20, i.e., $80.

In other words, in this simple example, Transpower could increase its transmission charges to the customer by $23.50 and not violate the price cap (provided it did not breach its annual revenue requirement). In other words, the more revenue that Transpower recovered through the optional 'additional TPM components', the less stringent the proposed transition mechanism would become.

For example, if Transpower opted to extend the AoB charge to a significant number of additional past sunk investments, its 'net value' might drop to such an extent that the cap ceased to be binding in any meaningful sense. It could then increase its transmission charges for the estimated beneficiaries of those investments by much more than the amounts indicated in the Consultation Paper. That would appear to be inconsistent with the purported purpose of the mechanism, i.e., to soften the price impacts from the redistribution of sunk costs.

Appendix B Previous reports

The conclusions in this paper have been informed by the analysis and materials contained in earlier papers by Axiom economists; namely:

- Axiom Economics, *Economic Review of Second Transmission Pricing Methodology Issues Paper, A Report for Transpower,* July 2016;
- Axiom Economics, *Economic Review of Distributed Generation Pricing Principles Consultation Paper, A Report for Transpower,* July 2016;
- Green *et al*, *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015;
- Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper*, A Report for Transpower, March 2014;
- Green *et al*, *Avoided Cost of Transmission Payments, A Report for Vector*, January 2014;
- Green *et al*, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Sunk Costs Working Paper*, 12 November 2013;
- Green *et al*, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013;
- Green *et al*, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions*, 25 June 2013;
- Green *et al*, *Transmission Pricing Methodology – Economic Critique*, February 2013;
- Green *et al*, *Potential Generator Market Power in the NEM, A Report for the AEMC,* 22 June 2011; and
- Green *et al*, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009.