Northpower

1 October 2019

Electricity Authority - Te Mana Hiko
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Transmission Pricing Review – 2019 Issues Paper

Thank you for the opportunity to comment on the Electricity Authority's 2019 Issues Paper on transmission pricing.

We enclose our submission and note that no part of it is confidential. We are also a member of the 'TPM Group' and endorse its submission, along with the accompanying expert report by The Lantau Group (**TLG**).

As our submission outlines, we have significant concerns about the current proposals, including the robustness of the supporting CBA. Similar concerns are also echoed in the TLG Report. Our overall conclusion is that the proposal does not provide a solid basis to support fundamental change to New Zealand's transmission pricing methodology. However, we acknowledge that some element of change to the existing regime is warranted and our submission sets out suggestions for change to address the issues identified in the Authority's consultation paper. We also support the general principles outlined in the TLG Report to guide future steps (section 1.6 of TLG Report).

We look forward to working with the Authority on the next stage of its review.

Should you have any questions about any aspect of this submission, then please feel free to contact me (09 983 0917 or Andrew.Mcleod@northpower.com) or Josie Boyd, GM Network (022 244 4409 or Josie.Boyd@northpower.com).

Yours faithfully

Andrew McLeod
Chief Executive
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2019 Issues Paper Transmission Pricing Review

1 October 2019

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1. Overview

Northpower Limited welcomes the opportunity to respond to the Third Issues Paper[1] in the Electricity Authority's (the Authority's) Transmission Pricing Methodology (TPM) review. No aspect of this submission is confidential. We are a member of the TPM Group and endorse its submission, including the accompanying expert report by The Lantau Group.

Northpower is not opposed to TPM reform, in principle. But, it must be the *right reform.* In respect of the current consultation, we believe that the Authority has not provided a convincing and coherent account of why its proposal would lead to better outcomes for New Zealand's electricity customers. Regrettably, we believe the proposal fails to meet the three most basic criteria of regulatory best practice; namely:

- it **would not be addressing a material and enduring problem** – indeed, the Authority has not articulated adequately a problem with the status quo that could not be 'fixed' within the existing guidelines or via more orthodox alternatives;
- the proposal clearly **does not represent the smallest intervention possible** – it would represent a substantial change to almost the totality of the TPM to implement a radical and internationally unprecedented methodology, at the expense of more incremental, conventional options; and
- it is **not based on robust economic foundations or a sound CBA** – the economics of the proposal simply do not stack up, and the quantitative analysis of costs and benefits contains errors that renders it totally unreliable.

Exacerbating matters, **the proposed cap would provide no meaningful protection** to our customers from the price shocks that would be very likely to result if the methodology was implemented. More generally, we struggle to see how the proposal fits within New Zealand's broader energy policy framework, which is focussing on encouraging energy efficiency and reducing our nation's carbon footprint. In particular, it is difficult to understand how encouraging more demand during peak periods would promote the achievement of these overarching goals.

We acknowledge there is room for improvement in the current TPM, but that the changes could be introduced and benefits realised in a far less disruptive, less risky, more durable and pragmatic way, with sounder economic underpinnings. Specifically:

- options can be implemented within the existing guidelines, e.g., **modifying the RCPD charge**, by increasing the number of peaks over which contributions measured, to 'soften' the strength of the price signal and to reduce the scope for avoidance behaviour; and
- **undertaking a pragmatic reallocation of the HVDC charge** (i.e., so that it is not levied solely on South Island generators) to 'take some of the heat' out of the TPM debate.

[1] Electricity Authority, *2019 issues paper, Transmission pricing review, Consultation paper*, 23 July 2019 (hereafter: 'Third Issues Paper').

2. Introduction

2.1 Background

The Authority's last proposal from December 2016 was roundly criticised by some of the world's leading experts on transmission pricing for lacking sound economic foundations.

The Authority's TPM review has now been going for seven years and has seen the proposal of five completely different methodologies. The most recent prior proposal – from December 2016 – was extensively criticised by some of the world's leading experts on transmission pricing for lacking sound economic foundations. Some common themes across the various expert reports and submissions lodged in response to that paper were that:

- the proposed pricing approach would send **economically perverse price signals**, compromising both static and dynamic efficiency;
- the approach would lead to **highly uncertain and volatile prices** – especially because it would be impossible for Transpower to estimate with any accuracy the benefits that would arise from investments over periods spanning decades;
- there would be **no beneficial impacts on the Commerce Commission's (Commission's) grid investment approval processes** – if anything, there would likely be more opposition to all investments, making life much harder for Transpower and the Commission;
- the Authority **had not given adequate consideration to more economically orthodox alternatives**, such as making more incremental changes within the existing guidelines; and
- the quantitative **cost-benefit analysis (CBA) was methodologically flawed**, containing extensive modelling errors and could not reasonably be relied upon to support the proposed changes.

The Authority acknowledged that the previous CBA was not fit for purpose. This led to the suspension of the review. The Authority has now put together a new CBA, but the methodology itself has remained largely unchanged from the December 2016 proposal that was critiqued so resoundingly. In short, it is the same proposal repackaged.

2.2 Good regulatory practice must inform any changes

The proposal would result in significantly higher prices for Northland consumers, without meeting the three most fundamental principles of good regulatory practice.

One thing that has not changed much in this latest proposal is the price impacts. As with previous proposals, it would lead to Northland customers paying more and some other parties paying significantly less. In particular, the design of the 'benefits-based' (BB) charges and its selective application to a relatively arbitrary sub-set of recent investments from which Northland is deemed to benefit would see a significant increase in the region's annual transmission charges. The Authority has estimated that the transmission component of our customers' bills may increase by 15.5% (Northpower) to 31.6% (Top Energy) in 2022. Alarmingly, that would be just the tip of the iceberg.

Those indicative figures are only for 'year 1' and do not include the impacts on final prices of the increases in distribution network costs and wholesale prices that would surely flow from the proposal – impacts that we explore subsequently. To be clear, we are not opposed to TPM reform *per se*. However, we have a responsibility to the customers within our network footprints – many of whom are low-income households experiencing energy poverty – to ensure that we are not passing-on higher transmission charges without good reason. Above all, we cannot reasonably lend our support to a proposal unless it meets the three most basic tenets of best regulatory practice; namely, that it:

- addresses a **material and enduring problem**;
- does so via the **smallest intervention possible**; and
- is based on **robust economic foundations** and a **sound CBA**.

We are troubled by the fact that *none* of these conditions have been met. In our view, the Authority has not addressed satisfactorily the plethora of criticisms that were levelled at largely the same methodology during the previous consultation round. There is consequently no reason to be confident that it would be a more efficient, equitable and durable methodology. The proposal also appears to be at odds with many other crucial energy market policies, such as climate change objectives and energy efficiency goals. In short, it does not represent a solid foundation for change.

2.3 Approach to this submission

Because so little has changed in the last two years, we have sought to target this submission on the main 'new' thing in the consultation package: the CBA. We have focused this submission on the broad categories of benefits that the Authority has identified in that new analysis. We have neither canvased every theoretical shortcoming in the proposal, nor performed a detailed assessment of the modelling. Rather, what we have tried to do is:

- highlight some of the more **obvious theoretical shortcomings** afflicting the purported sources of benefits – many of which have been identified by both ourselves and other stakeholders on multiple occasions over the last seven years;
- demonstrate what impact these problems have had – or should have had (i.e., if the Authority had been cognisant of them and factored them into its analysis in an appropriate manner) – on the CBA; and
- shed light on some of the more **glaring problems with the CBA** that can be seen without delving into the detail of the modelling – and illustrate why it is plainly apparent that the proposal would give rise to a *net cost* rather than a net benefit.

We also illustrate some of the more **specific problems with the proposed price cap**. This issue is of particular concern to Northpower because our customers would be facing price increases and the proposed cap provides no protection at all from price shocks.

We acknowledge there are some improvements that could be made to the existing TPM regime and to that end have suggested some **constructive ways forward** that would address the stated concerns of the Authority, reduce the risk of unintended consequences from regulatory intervention and avoid the substantial problems that would be associated with the Authority's proposal. These suggestions are supported by The Lantau Group's report, who provide a valuable and insightful international perspective on transmission pricing approaches.

3. Efficiency of grid use

The purported benefits from more efficient grid use are 10x greater than the entire net benefit estimate from the previous CBA – this does not pass a "sense check"

The Authority has claimed that $2.6b in benefits could be obtained through its proposed reform from 'more efficient grid use'[2]. The theory is that:

- the regional coincident peak demand (RCPD) peak charge is 'too strong' at present and causing customers to shed load or invest in distributed generation when it would be more efficient for them to use the existing spare grid capacity;
- replacing the RCPD charge with BB and residual charges – neither of which would have explicit peak components – would therefore result in additional grid usage, untapping a potentially enormous source of additional consumer benefits; and
- this would, in turn, avoid significant additional investment in batteries and other forms of distributed energy resources (DER), i.e., largely because customers would be using the grid, rather than harnessing those technologies to manage their demand.

However, we believe there are significant problems with this chain of logic in principle, and with the way in which the thinking has been factored into the CBA.

3.1 Overarching problems of principle

As a matter of general principle, there is no reason to expect that introducing a BB charge would yield billions of dollars in benefits from more efficient grid use. Perhaps the most striking aspect of the purported benefit is the number itself. The benefits supposedly on offer from greater peak usage have increased significantly since the last CBA. This alleged source of benefits alone is now said to be ten times greater than the *total* net benefit estimate contained in the previous CBA. That discrepancy is difficult to reconcile, considering that the two analyses were attempting to estimate *the same thing.*

3.1.1 A BB charge is not required to encourage more peak usage

Other more conventional options would be better than a BB charge at incentivising more efficient grid use if there were benefits on offer.

Setting aside the concerns around the $2.6b figure itself, if the existing RCPD peak price signal is too strong – which is likely – then there are many other ways to address that issue without completely sidelining the existing TPM. As we noted earlier, a basic principle of best regulatory practice is to address any problems via the smallest intervention possible, e.g., through incremental reforms. The Authority has proposed instead to re-write completely the

2 Third Issues Paper, p.21.

TPM by introducing a radical untested methodology and has ignored more modest, tried-and-test approaches such as:

- measuring contributions to RCPD over more periods (e.g., 1,000 or even 17,520 periods) and/or introducing more regions; or
- introducing an economically orthodox LRMC charge that varied in strength depending on the level of congestion.[3]

We also note the comments in The Lantau Group Report, which supports the retention of the RCPD charge, but amended to be no more than the long-run avoidable cost of transmission.

In our opinion, these options would perform at least as well – if not far better – at incentivising more efficient grid use. In other words, even if $2.6b in benefits were achievable, their attainment is not dependent on the introduction of the Authority's proposal. Accordingly, it is misleading to characterise those "benefits" as stemming from the *addition* of the BB charge. They would instead be a consequence of the *removal* of the RCPD charge (at least as currently fashioned), which could be a part of any number of reform options.

3.1.2 The BB charge would not address adequately future constraints

As grid constraints started to re-emerge in the future, the proposed approach would fail to provide adequate signals to customers of long-run investment costs.

The Authority has not provided a satisfactory explanation for what would happen under its proposal when constraints started to re-emerge in the future. One of the reasons it cites for proposing to do away with the RCPD signal – and for not implementing an LRMC charge – is that nodal prices alone can be relied upon to ensure efficient grid use and to incentivise efficient long-term investment. However, this claim is at odds with accepted economic theory[4] *and* with the Authority's previous statements. The Authority explained the limitations of nodal pricing succinctly in its TPM Working Paper:[5]

> *'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****.'* [emphasis added]

As the Authority highlighted, the fundamental economics of transmission services mean that nodal prices do not signal adequately long-run investment costs. For customers to be made cognisant of the effects of their near-term consumption decisions on Transpower's *future*

3 We acknowledge that the proposed Guideline allows Transpower the option of introducing a transitional peak charge, but this aspect of the package makes no sense. A peak charge – such as an LRMC price – is a *substitute for* a BB charge, not a *complement* for it. In other words, there is no reason to introduce the two charges in conjunction with one another – at least, not if the BB charge would be working in the fashion described by the Authority.

4 For a comprehensive overview of the limitations of the signals provided by nodal prices, *see:* Axiom Economics, *Economic Review of Transmission Pricing Supplementary Consultation Paper, A Report for Transpower,* February 2017, pp.13-15.

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

costs *before* they are incurred, something more is needed. Without that additional price signal in the TPM, consumption would be too high during peak periods, which would cause Transpower to invest sooner than would otherwise be the case if an explicit signal was rationing demand in some way.

3.1.3 The BB charge would send highly inefficient price signals

This aspect of the proposal is contradictory and confusing. If introduced, the BB charge would provide customers with economically perverse price signals.

The Authority suggests that its proposed BB charge would provide an 'implicit' price signal to which customers would respond.[6] The idea is that customers would predict the consequences of their consumption decisions on Transpower's future investment needs, then infer from this what their future BB charges would be and, where appropriate, 'rationally self-ration'. However, there is a flaw in this argument - if the Authority's claims regarding nodal pricing – namely, that they provide customers with all the signals they need to make efficient decisions – were true (which they are not), then why would there be any need for the TPM to provide any further price signals?

Put simply, these two propositions – that nodal prices can provide customers with efficient short-term and long-term signals, and that BB charges would supply an *additional* implicit price signal to *further* incentivise efficient conduct – are irreconcilable. If nodal prices did what the Authority says they do then, in such a world, the only logical TPM to have would be a non-distortionary tax. Nodal prices would be doing all the work to elicit desirable behavioural change, and the sole role of the TPM would be to not undo any of that work. A BB charge would clearly have no place in such a methodology. This aspect of the Authority's proposal is consequently contradictory and confusing.

Moreover, we believe that the price signals that would be provided by the BB charge would *not* work in the manner the Authority envisages. It is unrealistic to expect customers to be able to predict – and respond – to future BB charges. That would be an impossible thought experiment for most to undertake, which the Authority has acknowledged in other contexts.[7] In any case, even if customers would work out what their future BB charges would be, those prices would be sending economically perverse signals. BB price signals are not cost-reflective and, as many experts have pointed out previously,[8] that risks giving rise to undesirable incentives to change behaviour in inefficient ways. The Authority has not addressed any of those problems.

3.1.4 Other problems

It is unclear what benefits consumers are forgoing in the peak periods.

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6 Third Issues Paper, p.217.

7 *See for example:* Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2-E.3.

8 We refer the Authority in particular to the two most recent reports prepared by Axiom Economics on behalf of Transpower, which canvas in detail the substantial economic shortcomings of the implicit price signals that would be provided by the BB charge if it were ever implemented.

From a purely practical perspective, it is also not entirely clear to us what the Authority thinks is currently happening during peak demand periods that is causing so many ‘costs’ for customers. We accept that some larger users may be investing inefficiently in distributed generation, but the adverse impacts on mass market customers are more difficult to envisage. The way the Authority describes it one would be forgiven for thinking that customers were causing themselves huge inconvenience by delaying their dinners or switching off heaters, substantially reducing their total welfare. This seems somewhat far-fetched and not consistent with our experience of customer behaviour.

In reality, the majority of the demand curtailment that is currently taking place in peak periods is most likely things like distributors controlling customers’ hot water heating, e.g., switching it off at certain times of day. Most customers are probably not even aware that those things are happening. If that is the case then, logically, the additional consumption that would result if distributors stopped doing those things – or did it in off-peak periods instead – is not going to generate $2.6b in additional benefits. By definition, customers cannot benefit from something if they do not even know about it.

More generally, if the Authority is concerned about sending cost-reflective signals to customers so that they can make better decisions about whether to invest in new technologies, when to plug in their electric vehicles and so on, then introducing a BB charge with its unpredictable and inefficient price signals is quite possibly the *last* thing that it should be doing (particularly in a changing energy landscape, with the uncertainty of the impact of new technologies and investor and customer response).

Summary

There is no reason, in principle, to think that the proposed approach would give rise to large benefits from superior grid usage, i.e., from improved allocative efficiency. Instead, BB charges would be likely to incentivise highly inefficient responses from both load and generation customers. Moreover, if the RCPD signal is currently too strong, there are much simpler, more orthodox way to address that problem without compromising the ability to reintroduce a peak signal at a later time. The Authority has not accounted for any of these factors in its CBA and, as we explain in more detail below, it appears to have made many other errors as well.

3.2 Other concerns with the CBA

While we have not reviewed in detail the grid use modelling, we have some concerns with the way in which the analysis has been undertaken. We have discussed already the improbability of the $2.6b figure. We have also explained why any benefits from more efficient grid use could also be obtained from other more orthodox and simple approaches, such as via an LRMC-based charge or increasing RCPD period. Following a cursory examination of the model we also believe there are significant methodological deficiencies.

3.2.1 The model does not reflect how entry decisions are made

The CBA modelling has overlooked the fact that generators would account for future changes in nodal prices when making entry decisions – it is therefore unrealistic.

In the CBA, generator entry is modelled using a schedule of potential investments.[9] The model assumes that generators would decide whether to enter by looking at a single year of returns in the wholesale market and comparing them with long-run costs (see equation 25 in the Technical Paper). If the former exceeds the latter, entry occurs, with the lowest-cost plants investing first. An arbitrary cap is also placed on the amount of new investment that is assumed to take place in any single year, i.e., only two new investments can occur. However, none of these assumptions reflect how such decisions are made in reality.

Most importantly, the modelling ignores that generators make entry decisions based on projected future cashflows – just like firms operating in any market. Generators do not care what spot prices are *before* they enter – they make their decisions based on what they expect them to be *after* they invest. If a Generator thought that its entry would be followed by a sharp reduction in nodal prices, then there is a good chance that it would decide not to invest – even if prices happened to be 'high' at that time. This elementary principle has been overlooked in the modelling.

Rather, it appears that the Authority has assumed that removing the RCPD charge would lead to higher nodal prices, on average that, by the mid-2030's would prompt an influx of around $1.9b in additional generation investment. That new supply is then assumed to drive down wholesale prices and avoid the need for additional investments in batteries. This supposed reduction in wholesale prices is driving the lion's share of the net benefit estimate. However, an increase in generation of this magnitude would not actually happen because, for the reasons set out above, the businesses would account for the ensuing reductions in nodal prices and, in many cases, choose not to enter.

The economic viability of much of the additional investment that the Authority is modelling would be marginal at best, in *prospective* terms. In other words, the large wave of new generation investment that is driving the large net benefit estimate from 'more efficient grid use' would not eventuate. Indeed, it is not at all obvious why an enduring increase in demand in peak periods would lead to a price *reduction.* Why would the supply-side response outweigh the increase in demand – and by such a magnitude? It is all most peculiar and not at all consistent with conventional economic theory or how the market actually operates.

Further, the fact that the Authority is forecasting a wholesale price *increase* over the first decade is concerning given the impact this would have on consumer's end bills. For the reasons above, we do not consider the Authority can safely assume that wholesale prices will dramatically decrease once more generation is commissioned.

3.2.2 Most of the $2.6b is a bare wealth transfer

Most of the $2.6b estimate is simply a bare wealth transfer (i.e., not a benefit at all) – a significant modelling error

Even if entry decisions took place as depicted in the CBA modelling, the resulting wholesale price reduction would not give rise to $2.6b in net benefits. Final consumers would certainly benefit from those reduced spot rates the model is predicting since they would, in time, receive lower prices (e.g., reduced retail tariffs). However, nearly all of that benefit is simply

9 Technical Paper, p.54.

a wealth transfer from existing generators. There might be a small increase in overall demand (i.e., a reduction in deadweight loss), but the majority of that 'benefit' would come simply from generators receiving lower prices for electricity that they would have sold anyway at the previous, higher price.

Conservatively, we would expect this wealth transfer to account for at least 70% of the $2.6b benefit estimate. This is money that is flowing from one set of transmission customers (existing generators) to another (end customers). Ironically, the Authority has said that it does not count transfers when making decisions but, in this case, it has included erroneously around $2b as benefits. In other words, even if its proposal would lead to lower wholesale prices (which seems highly unlikely) it will not give rise to several billion dollars' worth of allocative efficiency benefits.

This represents a truly concerning error in the analysis. If the model's predictions are accurate (which we do question), then the Authority should expect to receive a wave of submissions from generators – including long-standing supporters of reform, such as Meridian – opposing the proposal vociferously. Any gains that, say, South Island Generators would obtain in the form of lower transmission costs would be dwarfed by the reductions in wholesale revenues that the proposal would bring about – if the modelling is to be believed. Logically then, if Generators still continue to support reforms even after seeing the modelling, the logical explanation is that they also find those predictions unbelievable.

3.2.3 Many substantial costs have been ignored

The Authority has not taken into account the majority of the additional costs that would need to be incurred in order to achieve the grid usage benefits that are supposedly on offer.

The Authority has not taken into account the majority of the additional costs that would need to be incurred in order to achieve the grid usage benefits that are supposedly on offer. For example, in order to meet the additional peak demand that the Authority forecasts – which is, in turn, producing over 95% of the estimated net benefit – substantial additional investment would be needed. For example:

- according to the Authority's own model, an additional $1.9b of generation investment would be required to meet that additional demand – the cost of which has been ignored in the CBA; and
- it is safe to assume that additional consumption that would arise from the removal of the peak signal would, in time, result in additional distribution network costs – none of which have been factored into the CBA.

The Authority's rationale for disregarding these additional costs is not robust. It states that it does not need to count the additional cost of the new generation in the CBA because the generation market is competitive and, therefore, any new investment can be presumed to be efficient.[10] This explanation does not stack up, as if the prices signals provided to generators are inefficient, then they may invest inefficiently. One of the main reasons the Authority is

[10] Third Issues Paper, p.47.

proposing to reform the TPM is precisely because it thinks aspects of it – such as the HVDC charge – could lead to inefficient generation investment.

Standing back, it seems evident that the only reason the Authority thinks that the $1.9b in forecast additional generation investment would be efficient is because it would be happening in response to its preferred pricing option. But, that is not how a CBA is supposed to work. The Authority should be testing whether the proposal would be efficient, based on the costs and benefits that would flow from it; not determining the costs and benefits to count based on its prior assumption that the proposal is efficient. The Authority appears to have started off its CBA by 'assuming the answer', which is not in line with good regulatory practice.

And even if all of that additional generation investment was efficient (which seems highly unlikely, considering the perversity of the 'decision rule' used to forecast it), someone still has to pay for it. It might be 'efficient' for a family to sell their existing home for $1m and to buy another for $1m. But, even if that was the right decision, they will not have an additional $1m in their bank account after the two transactions. It is called a *cost-benefit* analysis for a reason – both parts of the equation are equally important. This aspect of the Authority's modelling would be more aptly described as a pure *benefits* analysis.

The Authority's reason for ignoring additional distribution costs is equally problematic. It states that 'this is because the focus of the CBA is on transmission, not distribution'.[11] This contention is bewildering. The focus of the CBA is on the costs and benefits that would flow from a proposed change in the TPM. The impacts on distribution networks are *clearly relevant.* Distribution costs account for more than twice as much of an average retail bill than transmission costs, and so it is inexplicable that they have been ignored.[12] Distribution networks are sized to meet peak demand. Therefore, increased peak demand would inevitably lead to more distribution investment, which in turn would result in higher consumer prices.

The CBA also ignores the cost of the additional carbon emissions that could be produced if peak demand increases as forecast. Indeed, the Authority has extoled the importance of decarbonisation, but has given it no attention in its quantitative analysis. This is clearly contrary to broader government energy policy objectives. Finally, it is worth noting briefly that the Authority counts *as a benefit* $202m in 'avoided investment' in batteries (which is illusory, for the reasons set out above). This *avoided* investment cost cannot reasonably be counted as a benefit unless the model also includes the cost of the *additional* investment that would supposedly be needed to support it – including the $1.9b in additional generation.

3.2.4 The Authority has not modelled the methodology it has proposed

The Authority has not modelled its own proposal, because it has not incorporated the implicit 'shadow prices' signals that it has said would be supplied by the BB charge

[11] Third Issues Paper, p.46.

[12] Distribution costs account for 27% and transmission costs for 10.5%, *see:* Electricity Authority, 2018, *Electricity in New Zealand*, p.13.

The Authority's grid use modelling also fails to represent accurately the methodology that it has actually proposed. We noted above that the Authority is continuing to maintain that its BB charge would provide an 'implicit price signal' to customers to which they would respond when deciding when and how much to consume. If that is true, then the Authority should have factored those additional 'shadow price signals' into its grid use model. This does not appear to have occurred. This is immediately evident in Figure 1 below, which is a slightly modified version of Figure 7 from the Third Issues Paper.

Figure 1: Where are the shadow prices?

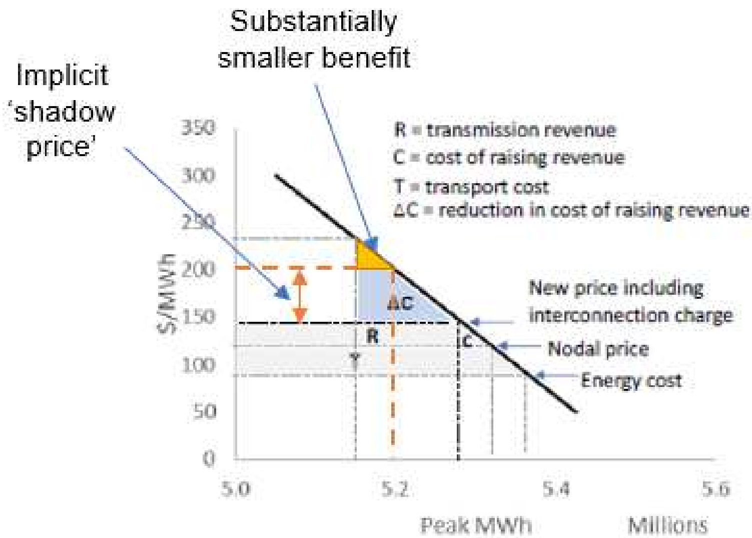

Figure 1 reveals that, if the Authority had accounted properly for the 'implicit price signals' that it contends customers would factor into their consumption decisions, then the total *effective* price that they would be facing would be higher. Its grid use modelling would therefore presumably have predicted a smaller reduction in the supposed 'cost of raising revenue'. In other words, this oversight is likely to have served to inflate further an already grossly overstated benefit estimate. More fundamentally, the grid use model does not accurately depict the methodology that is actually being proposed.

The grid use model would also produce exactly the same benefit estimate for *any number* of potential approaches. To yield the same benefit estimate, an approach simply has to be comprised *solely of fixed charges.* There is no need for those fixed charges to be based on an estimate of private benefits, or anything else. For example, Transpower could instead determine transmission customers' annual fixed charges by drawing numbers out of a hat. As strange as it may seem, this approach – which would clearly be absurd – would deliver the same benefit. That is not symptomatic of robust modelling.

Summary

Any one of the problems listed above would be sufficient in its own right to cast substantial doubt on the efficacy of the $2.6b estimate. Taken together, they render the analysis unreliable and, in our opinion, irredeemable. There is no reason to think that there would be any benefits arising from more efficient grid usage or more efficient investment in batteries and other DER. In light of the 'in principle' problems described in section 3.1 there is good reason to think that grid usage would be compromised, relative to other more orthodox options. For those reasons, the true net benefit arising from these factors would be either zero or negative.

4. Efficiency of investment

The Authority has suggested that its proposal would also deliver $43m in benefits from 'more efficient investment by generation and large load' and $77m from 'improved scrutiny of investment proposals' (these are modelled via 'top-down' analyses in the CBA). However, there is again no reason to think, as a matter of economic principle, that the proposal would lead to more efficient investment outcomes – and the CBA does not establish this either.

4.1 Overarching problems of principle

As a matter of general principle, there is no basis to expect that implementing the proposed methodology would yield any dynamic efficiency gains. Rather, as we have explained in past submissions – and as many other stakeholders have pointed out – the proposed approach would be altogether more likely to jeopardise long-term investment outcomes, to the detriment of customers – including by compromising grid investment approval processes.

4.1.1 BB charges would distort investment outcomes

The Authority's proposed pricing methodology would have significant adverse impacts upon the investment decisions made by both load and generation customers.

We noted earlier that nodal prices are not enough, by themselves, to provide efficient signals of long-term investment costs. The conditions for efficient 'shadow pricing' also do not hold, and so the Authority's proposed BB charge would not serve to 'plug this gap' in the pricing framework – despite its assertions to the contrary (which, as we have seen, cannot be reconciled with its own prior statements on the matter). This would have adverse consequences on the decisions made by both load and generation customers.

Firstly, as outlined in section 3.1.2, neither nodal prices nor BB charges would send efficient signals to load customers to curtail demand when constraints re-emerge in the future. This could result in Transpower investing to alleviate congestion sooner than it would have otherwise if an explicit price signal had been sent to customers via the TPM, e.g., an RCPD or LRMC-based charge. This would clearly serve to reduce dynamic efficiency, entailing substantial costs.

Secondly, levying BB charges on Generators would increase the costs of operating plants and, in turn their 'break-even' points. The result would be higher wholesale prices over the long-term. That would not necessarily be problematic, were it not for the fact that the underlying BB price signals are not able to be supported economically. As the Authority has been advised on multiple occasions, BB charges are not synonymous with forward-looking transmission costs and they would therefore risk giving rise to highly inefficient new generation investment decisions.

Compounding matters, levying the charges on Generators in the manner contemplated would send the counterintuitive signal that it is cheaper for them to build plants where transmission assets are older, on average. That makes no sense. The average age of 'sunk' infrastructure bears little or no bearing on the forward-looking costs of providing Generators with transmission services. Introducing a pricing methodology that discriminates based on the age of assets can consequently serve only to reduce dynamic efficiency by even more.

4.1.2 The Authority has not shown the HVDC charge to be inefficient

This Authority has not performed the analysis required to establish that the HVDC charge is acting as an inefficient tax – it could be an efficient locational signal

The Third Issues Paper also asserts that the HVDC charge gives rise to inefficient generation investment outcomes because it 'acts as a disincentive to invest in South Island generation.'[13] The HVDC charge is characterised as an 'inefficient 10% tax' on prospective South Island generation investments. However, this analysis overly simplistic, because:

- the reason for little generation investment in the upper South Island in recent years could be due to the fact that there has been little demand for the generation to be built over this time period, not the HVDC charge as implied; and
- the LRMC of supplying transmission services to generators located in the South Island is undoubtedly higher on average than for plants located in the North; and
- at the moment, the HVDC charge is the only thing that signals that cost differential to prospective investors.

It is therefore possible that the HVDC is providing an *efficient* locational investment signal. The only way to determine that for certain is to compare the size of the HVDC charge to the differential in LRMC between the North and South Islands. The Authority has not performed that analysis, and it therefore has no basis to conclude that the 'tax' on South Island generation to which it refers is inefficient. However, as outlined in The Lantau Group report, if the HVDC is distorting investment decisions, then we would support reallocation of these costs across North and South island Generators.

4.1.3 The grid investment approval process is not broken

This Authority has not identified any examples of past inefficient investments, or established that there is a problem with the grid approval process that the TPM could fix

As many submitters have highlighted throughout the consultation process, the Authority has not established that there is a problem with the current grid approval process that would be 'solved' by reforming the TPM. If anything, its analysis of historical investments has served simply to illustrate the substantial benefits that they are delivering to a broad array of customers. In its latest paper, the Authority claims to have identified three past investments that have bucked that trend and are, in its view, 'likely inefficient'. But, there are a number of problems with that assertion.

[13] Third Issues Paper, p.11.

Firstly, the three investments in question – North Auckland and Northland (NAaN), Otahuhu GIS and Upper South Island Reactive Support – were all reliability investments required to meet grid standards. It seems unlikely that the vSPD method that the Authority has used to measure benefits would capture all the benefits arising from those assets. In particular, those investments would be at their most valuable when something major goes wrong, and their existence means that the lights do not go out (an essential aspect of any transmission grid). However, those reliability and resilience benefits will not manifest in ongoing reductions in day-to-day spot prices.

Secondly, two of the investments – Otahuhu GIS and Upper South Island Reactive Support – received final approvals in late 2007.[14] This was only a few months before the onset of the global financial crisis and the ensuing flattening of load growth. Even if those investments might appear to be inefficient in hindsight, those judgements must be made based on what was known at the time. Moreover, as the Authority has acknowledged, its analysis spans only a short historical snapshot of the relevant assets' lives. This reveals very little about the overall quantum of benefits those investments might deliver of the remaining decades of their existence (and this also illustrating the difficulty in assigning benefits and beneficiaries at the beginning of the asset's life).

In other words, the Authority has still not identified any examples of 'inefficient' past grid investments.

More generally, it remains unclear to us why introducing a BB charge would suddenly cause parties to come out of the woodwork and engage vigorously and constructively in new investment approval processes. For one thing, there has been no shortage of engagement by parties on major investments. Indeed, the NAaN approval process took years to complete. And as multiple parties have highlighted, regardless of how the TPM is designed, customers' submissions are always going to be motivated by wealth transfers – not what is best for the market or wider New Zealand. It is therefore always going to be the Commission's job to sort the wheat from the chaff when reviewing submissions – the TPM cannot short-circuit that process.

To that end, the Commission is almost always going to be in a much better position to scrutinise investment proposals than the vast majority of stakeholders. It has the intellectual capital, information gathering powers and, perhaps most importantly of all, the internal resources.

That is why it is the *Commission's* job to perform that oversight function, as an expert regulator. That is its explicit statutory role. It is perhaps also worth noting that if the Commission thought that it could discharge that function more effectively if BB charges were implemented, then it has had ample opportunity to say so. The Commission can – and frequently does – lodge submissions in regulatory processes. The fact that it has not said a single word in support of the Authority's proposal is consequently quite revealing.

4.2 Other concerns with the CBA

The modelling of the more efficient investments that are said to arise from 'improved decisions by large loads and generation' ($43m) and from 'greater scrutiny' ($77m) are fundamentally flawed. The former estimate is irrelevant because the Authority has made

[14] A final decision on the North Auckland and Northland upgrade was made on 30 April 2009.

exactly the same mistake as Oakley Greenwood did in the previous CBA, i.e., it has not modelled the methodology being proposed. The latter estimate is unreliable, because of significant issues with the modelling and methodology.

4.2.1 The modelling does not reflect the proposed methodology

The Authority has made the same mistake that Oakley Greenwood did in the previous CBA by failing to model the methodology that is actually being proposed

The estimated $43m benefit from 'more efficient investment by generators and large load' is predicated on a basic misunderstanding of the price signals that customers would face under the Authority's proposal. The model assumes that the BB charge would be supplying those customers with an implicit price signal that reflects a rather rudimentary measure of LRMC. This is very similar to the approach that Oakley Greenwood employed to estimate a supposed source of benefits in its model – it used measures of regional LRMC as a 'proxy' for the signals that would be provided by BB charges. It was the wrong approach then and it is still the wrong approach now.

There is no reason to think that the BB charges that individual customers would face would reflect the LRMC of transmission. As we explained earlier – and as many experts have highlighted previously – benefits and costs are *not synonymous.* Two customers could face completely different BB charges, even though the LRMC of supplying them with transmission services was exactly the same. In our opinion, that makes absolutely no sense from an economic perspective and would lead to highly inefficient consumption and investment decisions – yet that is what the Authority is proposing.

In other words, although the Authority has tried to include forward-looking shadow prices in this part of its modelling (unlike in its grid use model – discussed above), it has included the *wrong* prices. If the BB charge was introduced, customers would face unique signals that reflected their own perceptions about the benefits that Transpower would assign to them. Those inferences might be well wide of the mark and, regardless of what those customers actually anticipated paying, those signals would not reflect the model's estimate of LRMC that is used as a proxy. The $43m estimate is therefore irrelevant – it is linked with a completely different methodology that the Authority is not proposing. It consequently cannot reasonably be included in the CBA.

4.2.2 The modelling of 'improved scrutiny of grid investments' is flawed

The entire benefit estimate hinges on a single, irrelevant datapoint that also happens to be overstated, i.e., it does not represent what the Authority thinks that it does.

The estimated $77m in benefits that is said to flow from improved scrutiny of grid investments is also unreliable. As we noted above, as a general principle, there is no reason to think that there would be any benefits arising from this avenue at all – in fact, it is altogether more reasonable to think that there would be an additional *cost* due to the controversy that would surround every proposal. Furthermore, the specific methodology that has been used to arrive at the figure of $77m is deficient in a number of respects.

The Authority has simply taken Transpower's future capital expenditure (Capex) program and assumed that different projects will be between 1% and 4% cheaper than forecast due to 'superior scrutiny'. The percentages it has selected are based on a single observation, i.e., between its draft and final determination for RCPD2, Transpower's enhancement and development (E&D) capex was reduced by 4.4%. The Authority has said that this provides an indication of the types of 'savings' that could be made from greater scrutiny if customers are subjected to BB charges and this therefore formed the basis for its assumed efficiency savings.

The first problem with this approach is that it is based on a single observation of no pertinence. The reduction in the E&D capex was as a result of scrutiny by the *Commission,* not customers. It is therefore irrelevant, since the Commission will be available to review all *future investments* as well. The real question is: what *additional* savings might be identified by consumer stakeholders who come out of the woodwork? In our view, the most likely answer is 'none', for the reasons we set out in section 4.1.3. In any case, the Authority does not have any objective basis upon which to gauge the size of that potential saving – the 4.4% figure is of no use at all.[15]

Even if the 4.4% figure *was* somehow germane to the modelling (which it is not), the Authority's analysis would still make no sense. The Commission presumably required that expenditure to be deferred because, in its assessment, the benefits consumers would obtain from it would not outweigh the costs. Any efficiency saving is therefore equal to the *difference* between that cost and the expected benefits. Ergo, unless Transpower was proposing to spend that additional 4.4% on things that delivered zero benefits, the number itself is also overstated. That additional 4.4% of proposed expenditure might have increased benefits by, say, 4.39%, in which case the 'efficiency gain' from disallowing the Capex would be 0.01%, not 4.4%.

Summary

The CBA has not established that there would be any net benefits arising from more efficient investments, including from superior engagement in grid approval processes. The far more likely outcome is that the proposal would compromise the efficiency of future investments, and of the grid investment approval processes. Consequently, the true net benefit from 'more efficient investment' would be either zero or negative.

5. Certainty and durability

The Authority has contended that its proposal would be 'more durable' than the status quo and would reduce uncertainty. It has estimated that, if implemented, the approach would deliver $26m in benefits in the form of increased certainty to investors. We consider this assumption is incorrect. The proposal would be anything but durable and would create a substantial amount of *additional* uncertainty and volatility for market participants and investors. The methodology used to quantify the $26m in benefits is also without solid foundation.

15 Moreover, the expenditure was not disallowed, per se. The Commission favoured instead a mid-period base capex re-opener. As such, there is a good chance that Transpower will actually wind up spending the 4.4% anyway, after that re-opener takes place.

5.1 Overarching problems of principle

All of the uncertainty surrounding the TPM has been created by the *Authority's reviews*

Prior to 10 October 2012 (when the Authority released its first issues paper), the TPM had been relatively stable. The extensive work of the two reviews that commenced in mid-2009 had concluded that, although the TPM might not be perfect, radical changes were not needed.[16] Since that time, all the uncertainty has been created by *the Authority's reviews*. In our opinion, if the Authority wants to improve certainty and durability it should therefore:

- leave the TPM as it is, put a stop to its review and issue a clear statement that it will not be looking at it again for the foreseeable future; or
- announce that it will consider instead more orthodox, less intrusive reform options – some of which we suggest in section 8.

In contrast, the Authority's current proposal does not represent a path to certainty and durability. Quite the opposite. As many submitters have highlighted previously, it would be an impossible task for Transpower to estimate with any accuracy the temporal dynamics of private benefits over the 30- to 50-year (or thereabouts) life of an interconnection asset when deriving BB charges. The extensive complications include the following:

- any private benefit analysis dependent on future nodal prices would require assumptions to be made about generator bidding conduct – all of which would be highly speculative;
- benefits might depend upon exogenous factors like forecast hydrological conditions (whether it is a 'wet' year or a 'dry' year) – introducing yet more uncertainty;
- Transpower would need to devise a method for measuring reliability and resilience benefits – neither of which are captured by the vSPD method;
- Transpower would need to come up with ways to assign charges to new entrants – which would be impossible to do without creating distortions – and design thresholds for reopeners and reassignments, all of which would create controversy and cost.

This point has also been highlighted in The Lantau Group report, noting the complexities around assigning future beneficiaries (including where cost is front loaded, but beneficiaries will largely be in the future).

It is not credible to suggest that the Authority's proposal would lead to greater durability and less certainty – it would do the opposite, resulting in more costs and ongoing controversy

Consequently, it is very unlikely the proposed methodology would be more durable and reduce uncertainty, rather the opposite would be true. As a simple 'sense check', it is perhaps worth noting that, now, when a customer comes to us and asks what its future charges are likely to be – including the transmission component – we can provide an answer.

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[16] The main exception to this was the cost allocation enshrined in the HVDC charge.

It might not be *completely* accurate, since the RCPD charge does shift around a bit, but we can provide a reasonably good indication. That would no longer be the case if the proposal is implemented. Our answer to the same question would become simply: “sorry, we do not know”. Major industrials seeking to weigh up future electricity costs when making major investment decisions would face similar problems. In our opinion, that would be most unsatisfactory.

Increased disputes are a likely product of the proposed regime – both through the grid investment process or Transpower’s BB cost allocation of new investments.

Those proceedings are likely to become bogged-down in never-ending arguments over the countless assumptions that went into the determination of customers’ benefit allocations, and as parties dispute the subjective assumptions that underpin the benefit estimates.

Customers are unlikely to support an investment just because it is ‘good for the market' but will care about minimising their own transmission charges. Parties might also oppose an investment because of concerns that they might be locked-in to paying charges that differ substantially from the benefits they actually derived. That is a very real possibility – in fact, it is quite likely. Benefit estimation would be an exercise fraught with uncertainty. It would be impossible for Transpower to make those assessment with any accuracy – certainly not over the 30- to 50-year lifecycles of interconnection assets. Extensive subjective assumptions would need to be made.

For that reason, even if parties wanted an investment to proceed, they would still undoubtedly lobby for their charges to be lower than whatever Transpower proposed. That is because each and every BB charge that Transpower proposed would be susceptible to the criticism that it was at least partly the product of ‘guess-work’.

Grid approval processes could consequently descend into unproductive disputes over subjective modelling assumptions. That would be an endless nightmare for both Transpower and the Commission.

There is no sound basis to believe that the proposal would deliver more efficient investment outcomes over the long-term. There is instead good reason to think that long-term investment decisions could be compromised if the proposal is introduced. The grid investment approval process would also become substantially more costly and contentious. None of these factors have been accounted for in the CBA.

Summary

There is no reasonable basis to believe that the proposed methodology would be more durable than the status quo or deliver more certainty. It is altogether more likely to lead to more cost, controversy and disruption. It would also lead to more uncertainty and needless volatility. This was precisely the reason why the Authority recommended *against* this ‘lock-in’ approach in 2012 – it concluded that it would not be durable.[17]

[17] *See:* Electricity Authority, *Transmission Pricing Methodology: issues and proposal, Consultation Paper,* 10 October 2012, p.101.

5.2 Other concerns with the CBA

The $26m benefit estimate is driven by arbitrary assumptions – one of which involves a random number that has a large impact on the result

Nobody could seriously dispute that there is currently significant uncertainty surrounding the TPM. It would therefore be beneficial to provide some clarity. However, as we noted above, it is the Authority itself that is responsible for creating that uncertainty through the highly unorthodox way in which it has conducted its review. It is therefore quite odd for it to claim that $26m in benefits can be obtained from, in effect, cleaning up the mess that it has created. By that rationale, the benefits from introducing the proposal would be greater still if the Authority extended its review for *another* five years. Against that background, it seems rather inappropriate to include this category of benefits in the CBA.

Moreover, for the reasons we set out earlier, the Authority's proposal would *not* clean up the mess – it would make things a lot worse. In any event, the foundational assumptions underpinning the $26m benefit estimate are fundamentally unsound. The Authority's modelling – as complex as it might appear at first blush – is driven ultimately by two key decisions that it has made. These are:

- its assumption that, if the proposal is implemented, 'uncertainty events' would happen every eleven years instead of every ten; and
- the selection of '100' as the benchmark 'value of uncertainty' – this is needed to produce a dollar value for the benefit estimate.

These values appear to have been randomly selected. It is not even clear what an 'uncertainty event' is intended to entail, much less why the Authority's proposal would lead to them happening less frequently. As for the second assumption, there is no science involved in the selection of the baseline value at all. The Authority could just as easily have picked 1,000, 1,000,000, or 567,893. All would have been equally valid. However, the benefit estimate *changes* depending upon which random number is chosen. This flaw undermines the credibility of the model and randomises the result.

Summary

The CBA has not established that there would be any net benefits arising from improved certainty to investors. In reality, the proposed methodology would heighten the existing level of uncertainty, create more volatility and undermine the durability of the TPM. Therefore, once more, the *true* net benefit from 'increased investor certainty' would be either zero or negative.

6. Fairness

The Authority has suggested that there are elements of the existing TPM that are 'unfair' and therefore liable to cause ongoing disputes and uncertainty unless they are addressed. It seems particularly troubled by the fact that there are currently customers – often in the South Island – who are paying for recent major investments that are being used to deliver services largely to other customers – often in the North Island. It also points out – rightly – that South

Island generators are not the only parties that benefit from the HVDC link, even though they are the only ones that pay for it.

The Authority has claimed that charging customers based on the proportion to which they benefit from investments would be more equitable and, as a consequence, the methodology would be less contentious and more durable. It has implicitly put a benefit of at least $18m on this 'improved fairness' in its CBA – a non-trivial sum, by any measure. However, it is not clear at all that the proposed methodology would be fairer than the status quo. Indeed, there are aspects of the proposals that appear to be manifestly *inequitable* to certain customers – including distributors based in the North Island, like ourselves.

6.1 Overarching problems of principle

Is it 'fair' to force customers to pay prices for new investments base on imprecise 'guesstimates' of benefits accruing over the course of several decades?

The Authority has claimed that its proposed allocation approach is 'fair' because it reflects the outcome that would arise in workably competitive market, i.e. "you pay for what you get"[18] to support its proposal. However, this is overly simplistic and quite misleading. Under the proposed approach, customers would be forced to pay prices for new investments based on an imprecise 'guesstimate' of the benefits that they might receive over a series of extremely uncertain scenarios over the course of several decades, and those charges might never change.

There is no known competitive market in which prices are set in this way. It is therefore far from clear that it would be fair to apply this approach even to *new* investments. For example, would it be fair to send a customer a bill for transmission services that purports to reflect the extent to which she benefits if, in truth, her true benefits are nothing like the sum claimed? And would it be fair to allow those charges to become less and less reflective of her 'true' benefits over time as market circumstances evolved? In our view, this is doubtful, to say the least. As we mentioned earlier, *the Authority itself* did not think such an approach would be durable when it started its review back in 2012.[19]

If BB charges were construed as being fair to apply to new investments, careful consideration would need to be given to those who will actually benefit. For example, an upgrade may be required for Auckland load growth, and as a result of load flows and nodal price increases, Northland may be deemed to benefit. However, Northland load may have not changed or even been the cause for the new investment and is only obtaining the same level of service (and benefit) it had previously. The benefit needs to be allocated based on an improvement, not purely because the investment is being used, because another party has used up all the capacity in the existing assets. In addition, a clear process would need to be set out on the timing of reviews should the use of the assets materially change over their lifetime.

18 Third Issues Paper, p.18.

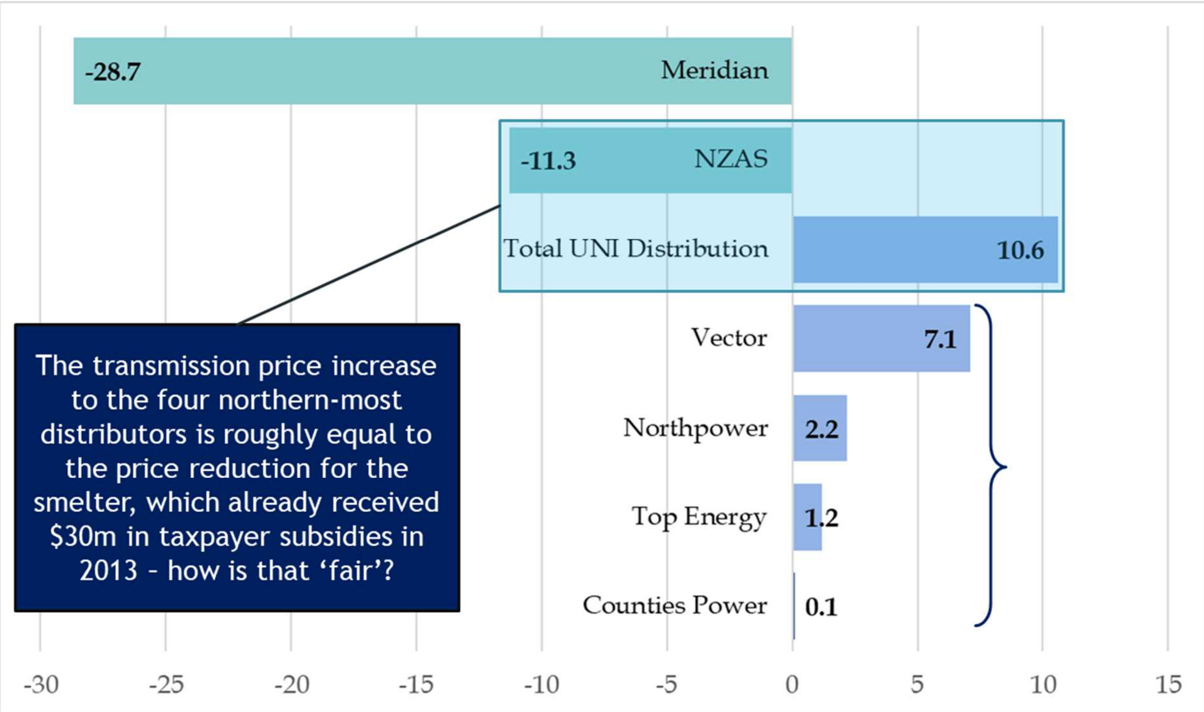
19 *See:* Electricity Authority, *Transmission Pricing Methodology: issues and proposal, Consultation Paper,* 10 October 2012, p.101.

Is it 'fair' to reallocate the transmission charges for seven relatively arbitrary recent investments so as to increase prices primarily for load customers in the upper north?

Even if it could be construed as fair to apply BB charges to *new* investments – which is highly questionable – it is clearly *not* equitable to subject some *existing* investments to the charge, but not others. On the face of it, there is some appeal to the argument that Christchurch consumers should not have to pay for upcoming upgrades, plus a share of the recent investments that have benefitted Aucklanders. But why reallocate just seven investments? Why not reallocate the whole grid?

If the Authority is concerned about Christchurch consumers, then why is it not also concerned about customers in Auckland and Northland? Under its proposal they would be paying for an arbitrary selection of recent investments, as well as for a share of older investments that may have benefitted predominantly customers in *other* parts of the country. North Island customers might also point to several other anomalous outcomes that would appear to be anything but fair, as Figure 5.1 below highlights.

Figure 6.1: Forecast transmission price changes, 2022, $m



In 2013, NZAS received $30m in government subsidies – collected, in part, from North Island-based taxpayers – to reduce its operating costs and prevent it from exiting the market. Figure 5.1 illustrates that the Authority has estimated that NZAS's total transmission bill would go down by around $11.3m p.a. if the proposal was implemented. Conversely, the total sum paid by the four northern most distributors would go up by $10.6m p.a. Customers in Auckland and Northland might well ask why it is 'fair' to ask them to fund yet another price cut for the smelter, given that they have done so indirectly already through their tax dollars.

The Authority has admitted that it has not been able to find any examples of other regulators reallocating the sunk costs of past investments. The recent Electricity Pricing Review also queried why the Authority was trying to undertake such reallocations. In our opinion, there is a good chance that such reallocations might be precluded by a government policy statement on transmission pricing. That rather begs the question of why the Authority did not wait for the final inquiry recommendations to be published before releasing its proposal. The timing of this consultation seems most peculiar in that respect.

Summary

It would not necessarily be fairer to apply BB charges to new investments, given all of the shortcomings with the proposed methodology. And it would be manifestly *unfair* to reallocate the past costs of existing investments – much less to limit that exercise to a handful of recent investments. It might also be said to be 'unfair' to change the way in which sunk costs are allocated so soon after a major investment programme. Rightly or wrongly, this might be viewed by some as it 'shifting the goal posts' and might even undermine the confidence that some participants have in future investment approval processes – and transmission pricing frameworks.

6.2 Other concerns with the CBA

The Authority's net benefit estimate increases by *$18m* if BB charges are *not* applied to the seven existing investments – this is a very big number to the *true* net benefit

The Authority's net benefit estimate *goes up by $18m* if the seven existing investments earmarked for BB prices are *excluded* from the BB charging methodology and subjected only to the non-distortionary residual charge.[20] This is unsurprising. Numerous submissions and expert reports have highlighted the fact that there can be no dynamic efficiency benefits achieved from reallocating 'sunk costs' – only static efficiency costs. The CBA simply reaffirms this well-accepted proposition.

Yet, inexplicably, the Authority claims that those seven existing investments should *still be subjected to BB charges.* It offers two reasons. Its first is that it claims that $18m is 'not significant in the context of the scale of the benefits estimated'.[21] In other words, it suggests that $18m is tiny, relative to the $2.7b net benefit it has estimated and can therefore be ignored. However, we are concerned that the net benefit estimate is grossly overstated. Indeed, $18m is a *very substantial* number relative to the *true* net benefit of the proposal which, in our view, is likely to be *zero or negative.*

The second reason it offers is that including the seven existing investments would give rise to various 'unquantified durability benefits'. The Authority therefore believes that the value of these 'durability' benefits would *exceed* $18m. However, for the reasons we have set out above, there is no sound basis to believe that there would be *any* benefits from improved durability. Rather, the proposal would *compromise* durability, certainty and fairness.

Specifically, the proposed approach would give rise to significant additional costs arising from the uncertainties and disputes that would result inevitably from its introduction. It also

20 Third Issues Paper, p.49.

21 Third Issues Paper, p.49.

would not promote competitive market outcomes or greater fairness. The approach is not 'market-like' in any meaningful sense and it is far from clear that it would be more equitable than the status quo. For example, reallocating the costs of just a handful of existing investments would seem to be both inequitable and illogical.

Summary

There was no justification for the Authority to disregard the results of its (admittedly fundamentally flawed) CBA and propose the application of the BB charging methodology to the seven existing investments selected arbitrarily in the Issues Paper.

7. Problems with the proposed price cap

We are alarmed that the proposed cap would provide virtually no protection at all against the price increases that would hit Northland if the proposal was implemented. The proposed capping methodology is flawed in numerous respects.

7.1 The cap does not protect against price shocks

The cap provides virtually no protection at all against price shocks and, for the vast majority of customers, it would be removed after a single year – rendering it almost pointless

The biggest problem with the cap is that it applies to a fraction of a fraction of a typical electricity customer's bill, i.e., to a *sub-set* of *transmission* charges.[22] Specifically, it would apply to any increases in transmission charges arising from the application of the residual charge and of the BB charge to the seven *existing* investments. The transmission component of a customer's electricity bill could therefore increase by much more than 3.5% (in real terms) in a year without the cap binding. That would clearly be the case for many customers, based on the indicative impacts provided by the Authority in the Issues Paper. Based on its calculations, in 2022:

- half of all distributors would be subject to price rises ranging up to 98% (Buller Electricity), 101% (Westpower) and 107% (Horizon Energy); and
- some direct customers face enormous price hikes, e.g., the initial increases for Pan Pacific (142%) and NZ Steel (146%).

These cannot be characterised as anything other than substantial price shocks. By way of contrast, the Commission has not allowed distribution revenues (and prices) to fluctuate by such substantial degrees when administering price/quality paths, rather limiting any step change increase and applying a x-factor in future years. Moreover, those numbers could also change significantly – for better or worse. For example:

- if Transpower decided to reallocate more than just the seven existing investments earmarked for BB charges, then these indicative charges would be affected.[23]

22 *See:* Proposed TPM guidelines, clause 49.

23 Proposed TPM guidelines, clause 49(e).

Incidentally, in our opinion, there is no logical basis for applying the cap to some existing investments but not to any others that Transpower might choose to revisit; and

- perhaps even more importantly, the cap would not apply to any *new* transmission investments that Transpower undertook.[24] In other words, if Northpower was allocated a large slice of a future transmission investment, this could lead to significant price increases for our customers and the cap would have no effect. It makes no sense to exclude future investments from the transition mechanism in this manner.

As if that was not bad enough, the cap does nothing whatsoever to protect customers from the potentially substantial increases in the *non-transmission* components of customers' bills. Between them, distribution and generation costs account for 59% of an average power bill.[25] As we explained earlier, if the proposal is introduced and results in an increase in peak demand then, with no explicit price signal available to ration consumption when constraints starts to emerge, it is not hard to predict what would happen. Namely, both distribution[26] and generation[27] costs would increase, pushing up retail customers' bills even further.

In addition, the cap can be removed almost as soon as it is applied. Specifically, the first year in which the price cap *does not bind* for a customer it is removed.[28] Based on the Authority's indicative modelling, the cap would not bind for 27 of the 29 distributors in 2022 – including for Northpower. If those numbers turned out to be accurate then, for all intents and purposes, the cap would be removed for the vast majority of customers almost as soon as it was applied. In other words, it would provide almost no protection for a single year and then vanish altogether. We struggle to see the point of having a price cap at all if it is designed in such a way.

Summary

The cap provides virtually no protection at all against price shocks. It applies only to a narrow sub-set of transmission charges, would not insulate against likely increases in other components of customers' bills (distribution and generation) and could be removed after a single year. Moreover, the indicative transmission increases clearly entail price shocks by any objective measure, despite the operation of the cap.

24 *Op cit.,* clause 49(d).

25 Electricity Authority, 2018, *Electricity in New Zealand*, p.13.

26 Recall that the Authority has consciously – and inexplicably – ignored distribution cost impacts in its CBA.

27 Remember that the Authority's CBA suggests that wholesale prices would *drop* in the long-term (i.e., by the mid-2030s) if its proposal is implemented. However, as we explained above, that result is predicated on a model that assumes that generators ignore future price impacts when deciding whether to enter, which is not the case at all. The large influx of additional generation that is driving the Authority's forecast wholesale price reduction therefore would not eventuate in practice and, in all likelihood, generation prices would be *higher* over the long term if the proposal was implemented. Indeed, conventional supply and demand theory suggests that an outward shift of the demand curve leads to a price *increase* not a reduction.

28 Proposed TPM guidelines, clause 50(k).

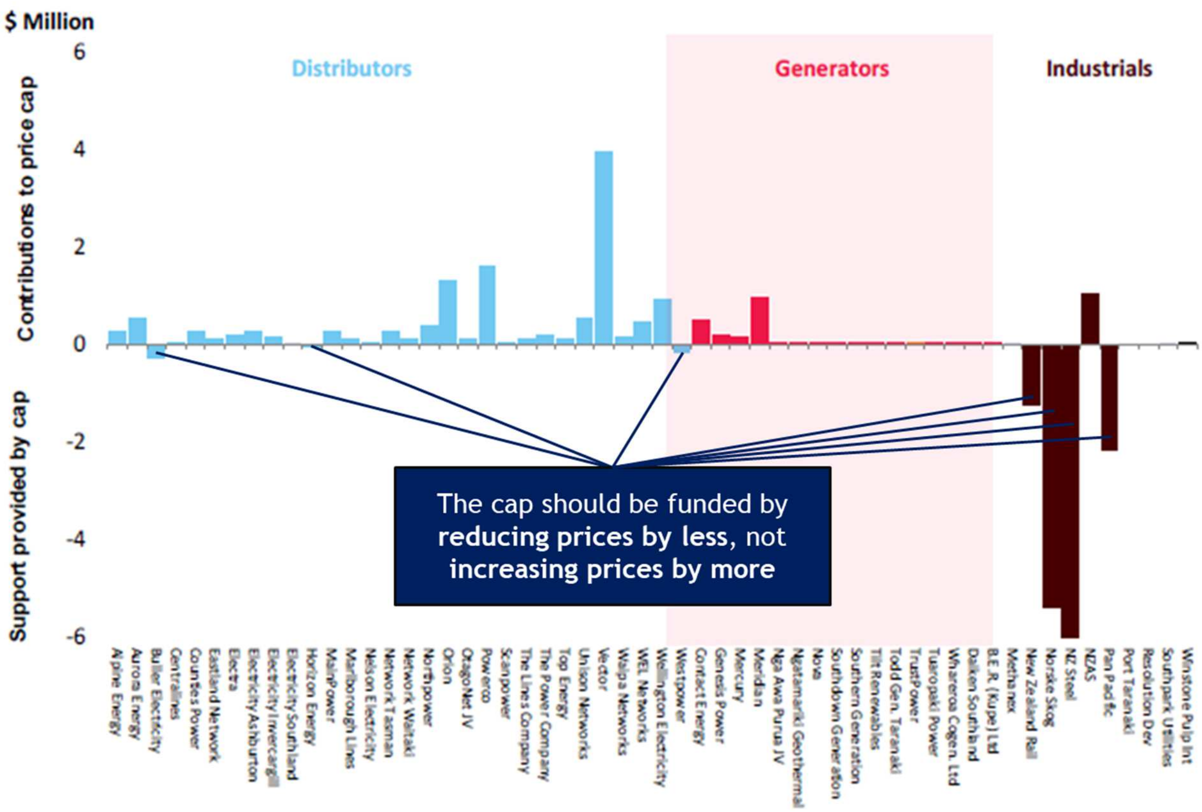
7.2 Specific elements of the cap make little sense

The cap serves primarily to *increase* the prices that most customers would otherwise pay.

There are some more specific elements of the proposed price cap that are anomalous. Perhaps most notably, the cap serves primarily to *exacerbate* the price *increases* that most customers would otherwise pay – including Northpower. We have never seen a price cap operate in such a counterintuitive way. In our opinion, instead of ‘funding’ the cap by ‘increasing price increases’, it would be far more logical to do so exclusively by ‘reducing price reductions’. In other words, the funds for the cap should come from parties poised to experience price *reductions* not from customers already facing price *rises.*

Figure 6.1 illustrates that there are several customers that fall into this camp. For example, Meridian’s estimated price cut is $28.7m in the first year and, as we noted earlier, NZAS is anticipated to receive an $11.3m drop (on top of the $30m government subsidy it received in 2013). The price cap could be financed by spreading these reductions out over a longer period, rather than by adding to the pain of customers whose prices are going to be going up in any case. Put simply, the funds for the price cap should be sourced from the proposals ‘biggest winners’, not the ‘losers’.

Figure 7.1: Indicative contributions to, or support from, the price cap in 2022



Source: Third Issues Paper, Figure 14, p.67.

The selection of the 2019/20 pricing year as the base year for the price cap creates several anomalies, since the proposal would not be implemented until 2022 at the earliest

The cap also exhibits several other curious elements. For instance, the 'base year' against which annual increases would be measured (i.e., the 3.5% escalations) is proposed to be the 2019/20 pricing year. That would be the last year of Transpower's second regulatory control period (RCP2). However, the Authority does not anticipate its proposal would be implemented until 2022 at the earliest, which would be during the *following* regulatory period (RCP3). That is highly significant because:

- Transpower's regulatory WACC will be significantly lower in RCP3 than in it is currently, due to a large reduction in the risk-free rate; and
- all other things being equal, this would increase the absolute size of the price increases that are permitted under a cap that uses 2019 as the base year as opposed to, say, 2022, i.e., 3.5% of a 2019 base price will be much higher.

The base prices would also include a 5-year weighted average of spot prices. This time period would therefore include the three-month period from early October last year, when wholesale prices increased well above 'normal' levels. The average spot price level was around three times higher than it had been in prior years. These unusually high prices would consequently push up the base value even further, resulting in a looser price cap.

Summary

Specific elements of the price cap make no sense. Most notably, it serves primarily to *increase* the prices that most customers would otherwise pay – including for Northland consumers. This seems counterintuitive. If the Authority persists with its proposed approach – which we do not think it should – it is imperative that it goes back to the drawing board and designs a transition mechanism that does not exhibit these fundamental design flaws and instead provides meaningful protection against adverse price effects.

8. Potential alternatives

The Issues Paper highlights that the RCPD-charge may currently be providing customers with overly strong incentives to curtail demand in locations where there is significant spare transmission capacity. It also implies that the locational signal provided by the HVDC charge may currently be *too strong*, since it is allocated fully to South Island generators, when North Island load also benefit.

We agree that these are both *potential* problems. In relation to the RCPD, we note the comments in The Lantau Group's report that:

- avoidance behaviour in relation to transmission costs should be addressed where it results in material and inequitable cost shifting amongst consumer groups;
- a peak period transmission charge carries important and valuable information and should be retained.

These are important points and have informed our suggestions for an alternative approach to TPM reform.

As discussed above, one of the problems with removing the RCPD charge and replacing it with the BB and residual charges is that there would then be no effective way for Transpower to signal its future costs to customers. Neither nodal prices nor the implicit shadow prices provided through the BB charge would achieve this objective. Moreover, the highly inefficient price signals that would be supplied via the BB charge would give rise to a plethora of other distortions that would result in sub-optimal consumption and investment outcomes. An enduring and explicit forward-looking price signal of some kind is needed.

There are also potentially simpler ways to reduce the strength of the locational signal provided by the HVDC charge, (assuming this is established as providing undue incentives to generators to locate in the North Island). In the following sections we set out two potential ways of providing an explicit forward-looking price signal and, if necessary, reducing the strength of the HVDC charge.

We strongly urge the Authority to give serious consideration to these more incremental, economically orthodox approaches, which are supported by the assessment provided by The Lantau Group's report. As highlighted in that report, these options present lower risk, particularly in an environment where the future is likely to be much different – but no one knows exactly how it will look. An incremental approach reduces the likelihood of unintended consequences which may result from more radical reform (particularly where there are significant assumptions around how markets and consumer behaviour will play out in the longer term).

We would also strongly encourage the Authority to ensure that any change in the TPM provides clear benefits in a reasonable timeframe, rather than over an extended period out to 2050. In a constantly evolving environment, to be too reliant on benefits arriving in the future puts at risk ever seeing them and will add to the issue of durability. The Authority's own modelling indicates that net benefits will only emerge after 10 years, but this is highly reliant on wholesale generation costs reducing due to increased supply. These benefits are too far in the future and too speculative to be reasonably relied on.

8.1 Modify the existing RCPD regime

Modifying the existing RCPD charge would have the advantage of addressing concerns of over-signalling capacity constraints, would deliver immediate benefits at little cost and retain a peak signal that could be flexed as required.

The simplest way in which to provide a more efficient, explicit forward-looking price signal to customers would be retain the RCPD-based charge, but to weaken that signal where there is sufficient capacity in the grid. This could be achieved by increasing the number of periods over which contributions to RCPD are measured, e.g., to 1,000 or, at the most extreme, 17,520. This would reduce the incentive for people to engage in cost avoidance activities and signal where there is capacity in the grid. This approach would not 'turn off' the signal completely, but it might do *most* of the job.

Moreover, if demand started to approach the available grid capacity at any stage in the future, Transpower could then reduce the number of periods over which the charge is allocated to 'sharpen' the signal. In other words, it could alter the strength of signal, depending upon the circumstances. This would have the advantage of being the most incremental reform – and would deliver immediate benefits for the smallest cost, consistent with the tenets of good regulation described earlier. Indeed, it could be accomplished without changing the existing TPM guidelines by Transpower performing a second operational review.

8.2 Modify the beneficiaries of the HVDC and reallocate charges accordingly

Reallocating the HVDC charge could be an incremental, pragmatic way of taking a lot of the 'heat' out of the current TPM debate, since it has been by far the most contentious issue

While the Authority has not established empirically that the HVDC charge is inefficient (as it ultimately comes down to an assessment of forward-looking *costs*, not *benefits),* there are some pragmatic reasons to think that the rationale for the current allocation – i.e., 100 per cent on South Island generators – no longer applies to the same extent.

Specifically, a key rationale for recovering all HVDC costs from South Island generators was the belief that they accrued the bulk of the benefits,[29] since the link transported energy predominantly for the South Island to the North Island.[30] Since that time, South Island generators have argued that they are not the only beneficiaries of the HVDC link. We acknowledge that there are shared beneficiaries, and therefore the 'bulk' of the benefits of the HVDC link do not accrue to South Island generators[31].

However, from an economic perspective, it does not much matter who benefits from the link. The pertinent question is whether the HVDC charge is recovering efficiently the long-run costs of the link without causing undesirable distortions. Historically it had been thought that charging South Island generators *did* achieve this objective, because:

- they would not be in a position to avoid paying this charge, and so levying the charge solely on these customers was thought to be a non-distortionary means of cost recovery;
- the variable costs of South Island generators (predominantly hydro) were small, and so transmission charges would not distort wholesale market bidding by, say, significantly disrupting the merit order of dispatch; and
- charging other beneficiaries such as North Island load would amount to charging load for a sunk cost, which was thought might reduce consumption below the social optimal.

However, with the passage of time it has become increasingly apparent that these rationales do not apply to the same extent. It is now *conceivable* that the HVDC link is unduly

[29] Transpower New Zealand Limited (1996), *Pricing for Transmission Services: Introduction to the Pricing Methodology to be Applied from 1 October 1996 - Second Edition, An information booklet from The Transmission Services Group*, p.8.

[30] For a more detailed account of the history of the HVDC charge, *see:* Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group,* 28 August 2009, pp.24-26.

[31] We note for example that the EA has estimated that more than 50% of the 'private benefits' of the HVDC link accrue to load customers. *See:* Electricity Authority, *Transmission Pricing Methodology: issues and proposal Consultation Paper, Appendix C Assessment of materiality of problems with HVDC charges under the current TPM*, 10 October 2012, §13.

discouraging generation from occurring in the South Island, i.e., because it is *over-signalling* the differential in the average LRMC of transmission across the two islands. If that was the case – and work would need to be undertaken to confirm that hypothesis - then it may be appropriate to reallocate the incidence of the HVDC charge to reduce the proportion paid by South Island generators.

This reform would again be quite incremental, pragmatic and serve to take a lot of the 'heat' out of the TPM debate. After all, the HVDC charge has long been a point of contention. However, this approach would also have drawbacks. Any such reallocation would again only be changing the incidence of payments for *existing* HVDC assets. The main problem with this approach is, again, that the resulting charges would not necessarily reflect Transpower's *forward-looking* HVDC costs, i.e., its LRMC. The revised charges might bear a *closer* resemblance to those long-run costs, but they may still be inaccurate.

Summary

Making incremental adjustments to the RCPD and HVDC charges would address the Authority's stated concerns around mitigating against inefficient avoidance behaviour, over-signalling of constraints and aligning the HVDC charges with current beneficiaries. These pragmatic options will deliver significant benefits for little cost, are consistent with good regulatory practice and should be given preference for that reason.