TPM Group Response to Electricity Authority's 2019 Issues Paper on Transmission Pricing Methodology

The TPM Group

We are a group which formed in 2016 because we were concerned about the changes to the transmission pricing methodology (TPM) Guidelines proposed by the Electricity Authority (EA). We comprise organisations from right across the electricity sector including large consumers, energy consumer trusts, stakeholder groups, electricity network companies, and electricity generators and retailers.

Current active members of the TPM group are:

- Counties Power
- EMA Northern
- Entrust
- Federated Farmers (Northland and Auckland)
- Horizon Networks
- Northpower
- Norske Skog Tasman Ltd
- Oji Fibre Solutions
- Top Energy
- Trustpower
- Vector

Background

This submission represents the initial response of the TPM Group to EA's 2019 issues paper: Transmission Pricing Review Consultation Paper (the 2019 Issues Paper) and the latest TPM proposal, and accompanying cost-benefit analysis (CBA), therein.

The TPM Group has engaged with expert economic advisors at The Lantau Group (TLG) to provide a robust independent assessment of the latest TPM reform proposals. This is intended to be a high-level review of the 2019 TPM reform proposal and accompanying CBA (rather than a deep-dive into modelling specificities and assumptions), in particular focusing on:

- the adequacy of the Issues Paper options analysis; and
- whether the supporting CBA is fit-for-purpose (including in the underlying assumptions and modelling approaches employed, and sensitivities tested).

In doing so, it focuses on the core components of the latest TPM design, namely the removal of separate charges for access to interconnection assets and HVDC assets, and the replacement of these charges with a fixed charge to assessed 'beneficiaries' of designated assets and a residual charge. It also considers a number of broader matters relating to the additional components, particularly the transitionary peak transmission charge.

The purpose of this independent review has been to assist the TPM Group in identifying whether there are any issues with the current TPM proposal, and if so whether viable alternatives exist. We set out what we consider to be the key findings of TLG's analysis, before drawing out our desired next steps.

We outline our views under the below three points, which reflect the key issues raised by TLG:

1. Clearly defining the case for change.
2. Limitations of the most recent cost-benefit analysis (CBA) to support the Issues Paper reforms.
3. A more pragmatic assessment of options for change.

We conclude by setting out our recommended principles to guide the way forward on the TPM proposal.

1. Clearly defining the case for change

We note the TLG's finding that there is a case for some change to the current arrangements and strongly agree with their view that the case is neither as strong as the 2019 Issues Paper's analysis suggests, nor that we can take comfort from the way in which the analysis is undertaken.

What we do draw out of TLG's advice, in particular, are the two broad, logical principles for change. First, that the current allocation of charges can be improved to reduce incentives for wasteful avoidance behavior; and, second, that there should be greater alignment between the EA's charging guidelines and the Commerce Commission's investment approval process.

Reducing wasteful avoidance behaviour

TLG make the point that with growing possibilities for avoidance behaviour, the case for a limited peak-period only charge is diminishing. However, it stresses that, even in spite of this, the RCPD charge still continues to serve as an important pricing signal, beyond that which can be provided by locational marginal pricing (LMP).

TLG's paper goes into greater details of why this is so, with the upshot being that some form of peak demand charge can still serve as an important role. That role is providing timely and accurate information on behind-the-meter (BTM) adoption costs and behaviours, and thus helping better evaluate future transmission and generation investment decisions. We therefore emphasise TLG's conclusion on this point that any future charging structure should be designed with these competing issues in mind.

Theory v practice for beneficiary pays

We note the views of TLG that the case for beneficiary pays is theoretically appealing on first viewing – on both efficiency and equity grounds. However, this theoretical nirvana, is a long way from the practical and contextual limitations of real-world electricity markets. The TLG report highlights several important reasons for this. Perhaps most fundamental of all is the fact that defining and identifying 'beneficiaries' is a complex and multi-dimensional task, particularly so in the case of transmission grid investments. Not least of these, are the far from uncontentious questions of how to account for inter-temporal affects and risks in any beneficiary-pays framework.

With these critical questions unresolved, the desired comprehensiveness and credibility of a beneficiary-pays approach is undermined, and there is a very real risk that the cost allocation is designed too narrowly. As such, we agree with TLG's conclusion that, while appealing in theory, there a still too many difficult (and largely unanswered) questions around implementation that make a more efficient and equitable outcome far from a certainty.

2. Limitations of the 2019 Issues Paper's Cost-Benefit Analysis

Putting any preferred set of TPM reforms aside, it is important to emphasise a number of limitations of the current CBA, which render it unfit-for-purpose and insufficient as a tool for determining reforms to the TPM. The CBA is being conducted at a time of increasing change and growing uncertainty, where sensitivities can have a huge effect on the estimated benefits (indeed the 2019 Issues Paper estimates the net benefits to be somewhere in the extremely broad range of $0.2bn to $2.7bn). This underlines the importance for comprehensively thought-out and defensible assumptions and sensitivity analysis.

TLG's analysis identifies several serious fundamental issues with the CBA, that fundamentally call into question its value and credibility in guiding the latest TPM proposal. We summarise these as:

More efficient grid use

This is the overwhelming driver of the CBA's net benefit figure, despite failing to be quantified in the previous CBA "because they were considered to be minor". The key underlying driver of this is the theoretical case put forward in the 2019 Issues Paper (albeit too briefly in Appendix E) that RCPD charges are inefficient, with locational marginal pricing (LMP) already provide efficient pricing signals. TLG sets out several reasons why this assumption has only limited, conditional support, in theory, as well as limited practical applicability in the New Zealand electricity market.

This fundamental limitation aside, there are also several key issues with the quantification process, which TLG's report elucidates in more detail: the potential overestimation of grid users' responsiveness to a price decline; the lack of any sound approach for separating net efficiency gains from wealth transfers; the failure to capture the costs of new generation investment; and the over reliance on benefits accruing from forecasted investments over a decade in the future. All of these areas require more nuanced consideration in order to deliver a robust CBA that can help differentiate between different reform options.

Investment in distributed energy resources (DER)

We draw attention to TLG's view that the forecasted 3,000MW investment in batteries in absence of any TPM reform, seems unreasonably high in the context of the overall New Zealand electricity market. This high level of investment comes about through the shifting of peak demand to the shoulder period, when the investment dynamics should instead focus on a levelling of demand across peak, shoulder and off-peak periods. Socially wasteful battery investment in the status quo is therefore materially overestimated.

3. A more pragmatic assessment of options for change

Given the issues with both the options analysis and CBA identified, we support TLG's conclusion that the 2019 Issue Paper is overly focused on emphasising (and quantifying) that a problem worth solving exists, and by consequence doesn't pay sufficient attention to the plausible options for reform, and nuances that can lead us to the most beneficial and implementable solution. The focus on one preferred reform has impacted the quality of the alternative options analysis.

TLG find that a broader set of options should have been considered, and that greater analysis should have been directed at differentiating the relative merits of these options, including the risks they pose (beyond any quantifiable net benefit). In this broader framework, TLG brings several important options to the fore that receive little attention in the 2019 Issues Paper.

(a) Focus on tweaking the charges already in place

Given the increasingly changing world, and the uncertain future this creates, the need to act flexibly and incrementally are of growing importance. The focus should not be on a once-and-for-all solution, but on a consistent set of underlying principles that drive good regulatory evolution over the long-term and through uncertainty.

With this in mind, TLG recommends retaining the RCPD charge to some degree. A downward revision of the RCPD charge in line with long-run average costs of transmission investments would reduce socially wasteful avoidance behaviour, while retaining a signal that would help to elicit important information on BTM uptake and so drive efficient transmission and generation investment in the longer term. We note that a simple change to the status quo that would support this would be to spread out the RCPD charge over more periods.

(b) A more pragmatic approach to beneficiary-pays

The 2019 Issues Paper offers little clarity on how a benefits-based approach would be implemented in practice, and without this the intended benefits may not be materialised. TLG note the fundamental trade-off in this respect, with a theoretically perfect beneficiary pays approach being inherently dynamic and complex to the point of impracticality. The TLG recognises the emphasis the 2019 Issues paper places on extreme case studies with clearly defined beneficiary groups, and thus seemingly fails to appreciate the (likely) many projects that would see little benefit from moving beyond the current approach.

There are still too many questions in terms of how this would work in practice, leaving a large gap between the conceptual appeal of a beneficiary pays approach, and the real-world implementability of such an approach. TLG recommends a more pragmatic way forward, which exercises a default approach similar to the status quo, and only implements a beneficiary-pays approach if certain thresholds (as to the concentration of benefits) are met. In order to do so, what is first needed is a government policy statement providing clarity on how benefits are to be defined (including difficult issues around risks and intertemporal benefits). This would help pave the way forward for a more practical implementable beneficiary-pays approach where the thresholds are met, as well as helping to align the Commerce Commission's approval process with Transpower's approach to cost recovery. In the meantime, a beneficiary-pays approach should be reserved for only the most unambiguous cases, where there is an undeniably concentration of benefits.

(c) A case for a lengthy transition

We first highlight a finding from the 2019 Issues Paper CBA which shows that the TPM proposal delivers no material net benefits for almost a decade. In this context, we share TLG's view that the case for an incremental approach underpinned by sound and consistent principles, rather than a once-and-for-all set of reforms, is desirable. With that in mind, we support TLG's recommendation that any TPM reforms are clearly signaled, but incrementally adopted over this period. While no material benefits would be foregone, at the same time this approach would help maximise stakeholder understanding and acceptance, and minimise price shocks and wealth transfers, as well as any unintended consequences.

(d) Limiting intervention in past decisions

We agree with TLG's guidance that any case for intervening in past allocation decisions must be extremely compelling from an economic efficiency perspective. TLG's recommendation is that the seven recent major grid investments do not meet this threshold, with no evidence that in aggregate the benefits are predominantly concentrated in given geographic areas or customer groups.

The TLG recommends that for the HVDC assets, on the other hand, a clear efficiency case for realignment does exists for which, given the ongoing contention and disputes, a principle of simplicity by recovering through a $/MWh charge on all North and South Island generators. We support TLG's view that, provided the direction of travel for future regulation is clear and, as we keep emphasising, based on an agreed set of underlying principles, then this decision would be compatible with the EA's focus on durability.

4. Our recommended set of principles to guide the way forward

The findings of TLG's independent assessment of the 2019 Issues Paper and accompanying CBA have helped shape a set of key principles that would support a transmission pricing framework that promotes greater efficiency and equity while being grounded in practical realities, and at the same time being transparent and adaptable to evolving circumstances.

We believe these principles should be adopted to inform and shape the EA's current reforms to the TPM and consider they would provide a pragmatic way to move forward within the context of the EA's current reforms, particularly given its continual focus on introducing a new transmission pricing arrangement that adopts a beneficiary pays approach.

Our recommended set of principles that should guide the EA in the next steps of its reform are as follows:

1. In respect of dynamic efficiency, avoidance behaviour with respect to transmission charges becomes an actionable concern only to the extent the "signal" that is driving avoidance behaviour is self-catalysing rather than self-correcting.
2. A peak-period transmission charge consistent with principle #1 should be retained because it conveys valuable information about the cost and effectiveness of a growing range of options available to customers behind their meters;
3. Other than to adjust transmission pricing as may be needed from time to time to achieve principles #1 and #2, retroactive reallocation is generally bad practice – and should be limited to instances where reallocation materially and unambiguously enhances efficiency.

4. The only exception to #3 pertains to the existing HVDC assets which are currently treated in a manner that likely distorts efficient generation investment decisions. Therefore, it is recommended to alter the HVDC cost recovery framework to be less distortionary and more equitable through a simple $/MWh charge applied to all North and South Island generators;

5. A benefits-based transmission cost recovery methodology is not needed (will not better promote the statutory objective or result in material benefits) and will increase dispute costs in almost all cases where benefits are already clearly broadly based. If the EA intends to proceed with any benefits-based methodology it should be limited to specific situations where there is unambiguous localisation of benefits (such as more than 60 or 70 percent), otherwise cost recovery should default to a broad-based framework for simplicity and costly dispute avoidance;

6. Any benefits-based cost recovery methodology should not be implemented without support by a Government Policy Statement to give essential guidance on inherently complex and especially contentious issues such as inter-temporal equity; and the treatment of competition, reliability, and safety benefits;

7. Subject to the above principles, the TPM Guidelines should not be overly prescriptive and should provide Transpower with flexibility to develop the detailed design features for a revised TPM along with appropriate implementation/transition arrangements;

8. Changes in the TPM should be clearly signalled but incrementally introduced so as to mitigate material price shocks, maximise stakeholder acceptance and understanding, and avoid risks of unintended consequences; and

9. The analytical foundation for changes to the TPM now or at any time in the future should be comprehensive and robust.

Importantly these recommended principles rely, in part, on the provision of a Government Policy Statement (GPS) to clarify Government's priorities for the electricity sector. Including with respect to distributional impacts of this reform on some of New Zealand's most vulnerable communities and the risks the reform poses for achieving the Government's climate change objectives.

It is anticipated that a GPS will be provided by the Government following the release of the Minister's decisions with respect to the Electricity Price Review and so it is perplexing why this Issues Paper has been published before this has been provided. Regardless, we hope these principles will provide a constructive basis for further discussion and response during the cross-submission process and urge the EA to consider incorporating a public hearing into the next stage of consultation to help further facilitate this important discussion and enable an opportunity for the Group and TLG to present directly to the EA Board.

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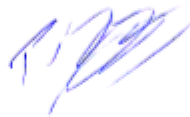

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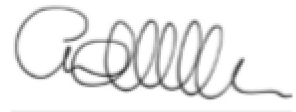

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FINAL

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Review of Transmission Pricing Guidelines Issues Paper 2019

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1. SUMMARY

1.1. OVERVIEW

The issues being debated and analysed in the ongoing consultation on New Zealand's Transmission Pricing Methodology (TPM) have been around a long time and they are inherently complicated by the prospect of material short-term wealth transfers and uncertain longer-term economic efficiency benefits. Over many years, the Electricity Authority's (EA) processes and findings have followed a winding and difficult path. The underlying issues can be made almost as complex as desired, and the more one zooms in, the more complex yet again it can all become. Some perspective is important, as transmission accounts for perhaps only 10 percent of overall costs of electricity supply in New Zealand. A necessary practical consideration is therefore to find the right balance between enhancing the pricing methodology and avoiding unintended consequences or risks.

1.2. EMERGING THEMES

We see several strengthening themes compared to past debates on these issues. The Authority is rightfully focussed on concern that the pricing methodology should not incentivise material cost avoidance behaviours (cost shifting). And we see the older, continuing theme that beneficiaries of transmission investments should pay for those investments. We also see a third and newer theme – more extreme in nature – that the use of locational marginal pricing (LMP) in New Zealand's wholesale market is sufficient to justify the removal of a peak demand-based transmission charge entirely.

All three themes have practical implementation challenges and risks. In our view, the proposals being advanced to address these themes go too far, perhaps emboldened by a strikingly flawed CBA that is not structured or framed appropriately for the purpose to which it is largely being used.

Accordingly, at a high level, we have three principal recommendations:

- Retain the RCPD charge but reduce it significantly by spreading it over more hours to the point where it is recalibrated to be no greater than the long-run avoidable cost of transmission as estimated by Transpower;
- Do not adopt the beneficiary pays orientation as proposed, but rather first resolve the many prerequisites required to enable a beneficiary pays approach to be effective in the New Zealand context; and
- Do not revisit the legacy investments, with the exception of the HVDC.

Much work has been done along each of these lines such that Transpower is in a good position to advise on the appropriate recalibrated level of the RCPD charge. In contrast the appropriateness and effectiveness of a switch to beneficiary pays depends:

- Firstly, on agreeing a beneficiaries-based framework given the complexity of benefit types and the implications for how they are allocated. Given the significant and material public policy impact on transmission investment requirements, any such agreement should be informed by a Government Policy Statement on transmission benefits and guidelines on how they should be considered and recovered; and

- Secondly, on clearly and unambiguously identifying and closing gaps and potential inconsistencies between treatment and calculation of benefits during the Commerce Commission (ComCom) driven approvals process and their treatment, calculation, and implications when benefits are considered in EA-driven pricing methodology application.

It is neither necessary nor appropriate to switch away from an RCPD-based charge at this time, though there is a case for recalibrating the RCPD charge and continuing to develop and evaluate an appropriate beneficiaries-based framework.

1.3. Key Challenges

The key challenges that complicate any change to the current TPM can be summarised succinctly as follows:

- **Distant and Uncertain Benefits for Immediate Costs and Arbitrary Wealth Transfers**. Any material change to the pricing methodology risks creating more wealth transfers up front (pain and arbitrariness) for uncertain economic benefits that are largely realised much later. A preferable set of changes would recalibrate the RCPD charge and focus on enhancing and refining the beneficiary pays approach.

- **The Vanguard is a Risky Place to Be.** Some of the concepts proposed for New Zealand would be unique in their application in a market of the small size and level of competition as New Zealand. Often even the same concepts as may appear to be adopted in other markets have much broader application – such as across regions that may be many times bigger than New Zealand, meaning that the New Zealand implementation of the identified theories will be far more granular and detailed – and thus more susceptible to error, rent-seeking, or market power;

- **Focus on the Entire Process not Just the TPM.** The current process for transmission plan development, approval, and cost recovery is tripartite in that it involves Transpower, ComCom, and the Authority for different things at different times. Accordingly, the prospect of misalignment, mis-translation, and differential interpretation cannot be ignored. A prerequisite for realising benefits in theory is that the beneficiaries are actively part of the approval process – but this presupposes consistent views of the benefits to be considered in both approvals and cost recovery through the TPM. The required processes by which the "baton" of considered benefits, associated analyses, and informed participation passes between Transpower and ComCom for approvals and then again between Transpower and the Authority for pricing (cost recovery) have not been described; perhaps have not been agreed; and in our view cannot even be implemented appropriately without additional guidance, such as through a Government Policy Statement, on the treatment of various types of transmission benefits.

- **Resolve the HVDC Charging Regime.** The HVDC charge for historically incurred HVDC investments, which is currently imposed only on South Island generators (though it was once allocated very differently), is unfair and distortionary, and should be resolved in a simple, practical way – even if it requires a unique treatment; and

- **The Perfect is the Enemy of the Good.** A flexible, incremental "learning" approach is warranted. The energy world is clearly changing with the prospect of numerous emerging and future sources of disruption, so the prospect of a once-and-for-all solution is unrealistic, though the underlying principles and concepts supporting an evolving solution appear robust.

The work the Authority has done, even where we disagree with it or would have done something different, has been useful in establishing that some level of change is appropriate. Nevertheless, the CBA accompanying its 2019 Issues Paper (2019IP) is flawed conceptually and ripe for significant criticism and concern with respect to many points of detail.

In particular, the CBA sets up a comparison between two extreme scenarios and then obtains an extreme result. Many may focus their criticism of the CBA on specific assumptions or calculational methodology concerns, but we see a more fundamental problem. The base "business-as-usual" (BAU) case is so significantly flawed from the start and the alternative case is so extremely different from the flawed BAU case that the results cannot help but be both flawed and extreme. As a result, we strongly advise that the efficient grid use benefits be ignored; the efficient battery benefit be questioned; and the beneficiary pays benefit be discounted.

The inherent issue in the BAU scenario is that the current RCPD charge is *clearly far too high* during the peak period (to the point that we do not need a CBA to tell us about the potential benefits of reducing this charge). This problem can be fixed easily by recalibrating the RCPD charge; and doing so would create a much more appropriate basis for then evaluating the relative benefits of possible further refinements. Yet this is not the focus of the Authority's analysis or proposal; the focus of the core CBA is very much on the alleged benefits of switching all the way from the current RCPD charge which is unambiguously too high, to a charge that is broad-based across all usage. Unfortunately, the wide range of possible, and more pragmatic, alternatives in the 'middle ground' of these two extremes remain overlooked. Accordingly, the case for the 2019IP specifically proposed recommendations is weak (as a case, let alone a strong one, against eminently plausible alternatives is not made), though many of the associated inferences and discussion points are still useful. Instead, we strongly urge consideration of a modified or transitional alternative approach that addresses the identified problems more efficiently and effectively while robustly avoiding additional risks.

1.4. The CBA Scenario Comparison Needs to be Relevant, But Isn't

Consider a study to compare two different cars. One with two tyres and one with four tyres. And then assume each is driven in some simulated way for thirty years and the results compared. Clearly, the car with two tyres is going to be problematic from the start, scraping the street if it goes anywhere at all. Why would we even consider including a car with only two tyres in the analysis in the first place? The more interesting question would be what type of tyres would be better for our car? Tyres with better grip but that wear out faster; or tyres that are harder, get better petrol efficiency, and maybe last longer but are worse in the rain? And so forth. There are many types of tyres we might have analysed, with many important options to consider. But all we did was determine that four tyres are better than two.

Or consider two rocket ships. One has a guidance system with a known flaw that will cause it to use too much fuel and fail to reach its destination. The other has no such flaw but depends on an unproven propulsion engine. A simulation compares the two ships. The first ship never makes it. The second ship does. Yet the value of the simulation is misleading. The first ship needed no such simulation, as the guidance system flaw was already known. The second ship needs a completely different simulation to tease out the risks and performance issues associated with the new propulsion system. A simulation comparing the performance of the two rocket ships does not provide much insight, as the specific issues that need to be considered in each case are known already, and are very different.

Now, consider that the CBA principally focussed on a BAU scenario in which the existing RCPD charge during peak hours is higher than any reasonable estimate of avoidable long-run cost of transmission and eventual behind-the-meter alternatives. Accordingly, even before commencing the analysis we know that compared to a similar scenario with just the RCPD charge smoothed out and greatly reduced at peak, the BAU case will be inferior. Like the car and rocket ship analogies, however, we know this even before we start the analysis. Accordingly, the analysis cannot add nearly as much to our understanding of the problem or the nature of potential solutions as we need to know. The analysis merely reinforces recognition that something that is already flawed (but easily fixed) will probably produce an inferior result (if it is not fixed).

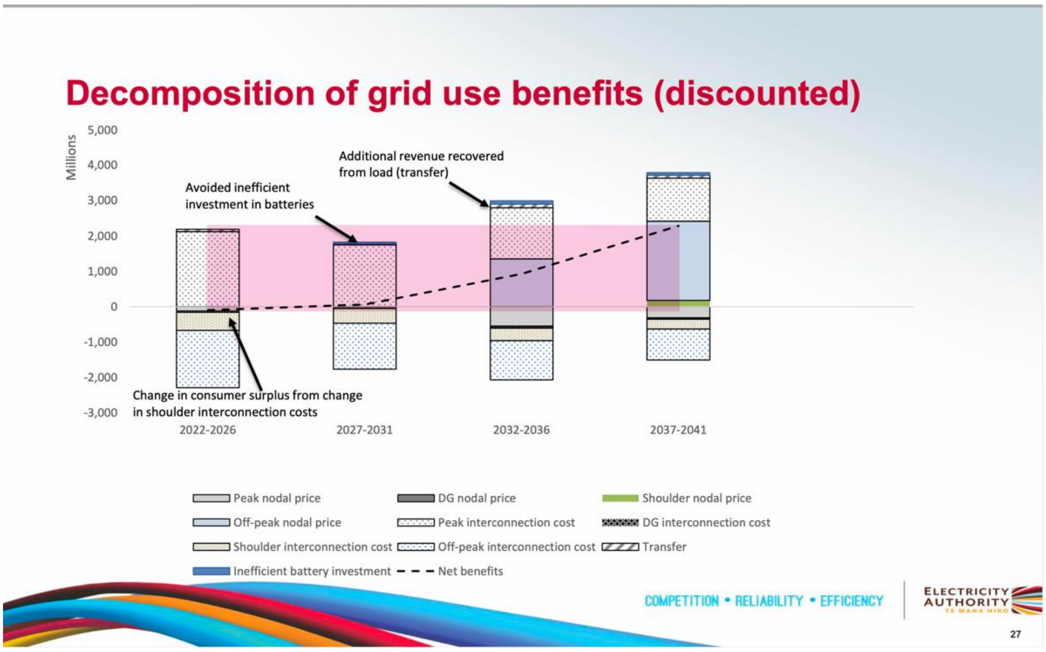
It is generally not good analytical practice to jump from a BAU case that starts with a clear economic flaw to an extreme case at the other end of the spectrum unless the point is simply to hammer home a high-level headline message. There is a middle ground of prudent and attractive and relevant options that offer solutions that involve similar benefits and less risk compared to proposing a first-of-a-kind approach in a small, volatile market. The decision variables for choosing amongst these options, however, are not part of the CBA. Like the car and rocket ship analogies, the more important considerations revolve around other attributes such as risk, clarity, implementability, workability, certainty, and effectiveness.

We think that when these factors are given more weight, the preferred result is to retain but recalibrate the RCPD charge; pause and focus on more fully defining beneficiary pays framework and associated processes; and sort out the HVDC cost recovery in a simple, and straightforward way. Where changes are introduced, they can and should be gradual and directional in nature, with clear signals for future decisions.

1.5. TIMING

One of the more striking things that almost certainly gets overlooked by someone just focussing on the headline CBA net benefits is the underlying time profile of those net benefits. Notably, the CBA highlights low and even negative net benefits in the early years with the alleged major net benefits arising almost a decade from now, as shown in Figure 1.

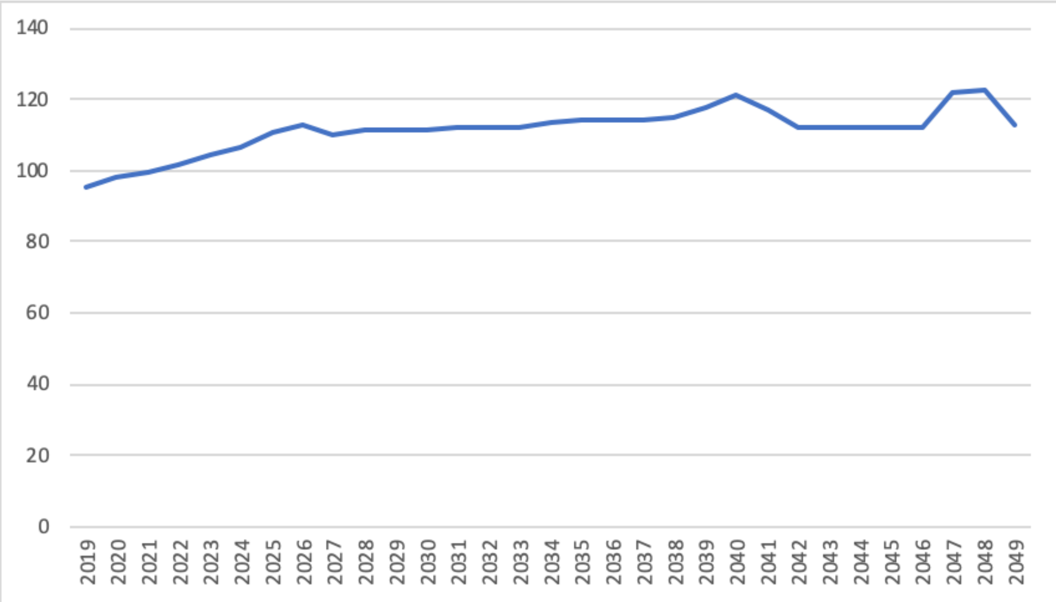
Figure 1: CBA Estimate of Grid Use Benefits Over Time



Discounting is one way to reduce the impact of future benefits for evaluation in the present, but when benefits are extremely back-end-loaded, discounting alone is rarely sufficient to uniquely resolve to a particular recommendation. In part this is because with largely deferred net benefits, you can usually also defer or evolve a change to take advantage of additional information that becomes available over time. The 2019IP strangely has not developed alternative approaches that more specifically seek to improve the overall benefit timing profile, either by reducing the small negative benefits initially or by seeking to understand the drivers and trigger points or thresholds that are driving the benefits post 2030. It is very likely based on what we can tell that a recalibrated (lower) RCPD charge would reduce the negative net benefits in the early years compared to the Authority's proposed scenario.

The benefits that arise in the CBA post 2030 are related to the extreme difference in RCPD charges between the base case and the alternative case.[1] These net benefits begin to kick-in from 2030 after the RCPD charge in the BAU case has increased approximately 20% relative to 2019 as shown in Figure 2.

Figure 2: RCPD Charge as Modelled in BAU Case[2]



Accordingly, there is both time for an orderly transition and no strong argument for a radical elimination of the RCPD charge at this time. A process that manages the RCPD charge to be a long-run transmission cost signal not only has merit but can be implemented out to 2027 and beyond without any material loss of benefit. During this time, changes in the TPM should be clearly signalled but incrementally introduced so as to mitigate material price shocks and wealth transfers, maximise stakeholder acceptance and understanding, and limit the risks of any unintended consequences.

A lengthier transition would also allow time for the drafting of a Government Policy Statement to provide guidelines on the definition, identification and treatment of different types of benefits. In the absence of this, a move to any meaningful beneficiary-pays style approach is not tractable. While the policy statement is under review, the beneficiary-pays approach should be restricted to completely unambiguous cases, where the beneficiaries (and non-beneficiaries) are clearly identifiable and separated. Then, once the Government Policy Statement is well understood and in place, the beneficiary-pays

1 By definition, as this is the main difference between the cases.

2 TLG analysis based on data available from the Authority. All_major_CAPEX - plus add in forecast revenue from unapproved major capex. Central scenario

approach has the scope to become somewhat more ambitious, albeit subject to the caveats, threshold tests etc.

Together, this more gradual evolution from the status quo, based on a transparent, well-defined set of principles that guide TPM reform in a clear and predictable direction, would help to ensure maximum understanding and acceptance amongst stakeholders, and thus minimise implementation risks.

1.6. A Principled Solution

The key principles that inform our views and shape our recommended TPM approach and our associated comments to the Authority, are set out below:

1. In respect of dynamic efficiency, avoidance behaviour with respect to transmission charges becomes an actionable concern only to the extent the "signal" that is driving avoidance behaviour is self-catalysing rather than self-correcting.

2. A peak-period transmission charge consistent with principle #1 should be retained because it conveys valuable information about the cost and effectiveness of a growing range of options available to customers behind their meters;[3]

3. Other than to adjust transmission pricing as may be needed from time to time to achieve principles #1 and #2, retroactive reallocation is generally bad practice – and should be limited to instances where reallocation materially and unambiguously enhances efficiency.[4]

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3 Such information may come at some short-term static efficiency loss but is valuable in planning and policy making in relation to overall grid investment strategies and costs as well as risks associated with long-term generation investment. It conveys useful information as energy markets continue to develop over time and adjust to new technologies.

4 In simple terms, if it is possible to reallocate or restructure in a way that "grows the pie", then it is at least theoretically possible to compensate losers in any reallocation. Such situations while complex, can be worth resolving. Otherwise, the purpose of the reallocation is simply to re-reallocate, and there is no gain. Any action that raises the possibility that stakeholders will see re-allocation or even re-re-allocation as the outcome of a game (rent-seeking) is generally bad practice. In some instances, if it can be shown that an in-place allocation violates a previously agreed allocation principle such that ex post correction reinforces rather than undermines the robustness of future agreements, then this too can be considered. But the point more generally is that there needs to be reason related to enhancing efficiency and related to honouring commitments. The concept of "efficient breach" has some relevance here, as it makes sense to introduce a change if the result is to reduce costs or free up a trapped resource (efficiency).

4. The only exception to #3 (and it is not really an exception as much as it is an example) pertains to the existing HVDC assets which are currently treated in a manner that likely distorts efficient generation investment decisions. Therefore, it is recommended to alter the HVDC cost recovery framework to be less distortionary and more equitable through a simple $/MWh charge applied to all North and South Island generators;

5. A benefits-based transmission cost recovery methodology is not needed (will not better promote the statutory objective or result in material benefits) and will increase dispute costs in almost all cases where benefits are already clearly broadly based. If the Authority intends to proceed with any benefits-based methodology it should be limited to specific situations where there is unambiguous localisation of benefits (such as more than 60 or 70 percent), otherwise cost recovery should default to a broad-based framework for simplicity and costly dispute avoidance;

6. Any benefits-based cost recovery methodology should not be implemented without support by a Government Policy Statement to give essential guidance on inherently complex and especially contentious issues such as inter-temporal equity (when benefits are disproportionately in the future such as for economic development or when augmentation or expansion include room for growth, such as for EV demand or because of economies of scale); and the treatment of competition, reliability, and safety benefits;[5]

7. Subject to the above principles, the TPM Guidelines should not be overly prescriptive, being designed to strike a balance between increased certainty and flexibility for Transpower to develop the detailed design features for a revised TPM along with appropriate implementation/transition arrangements;

8. Changes in the TPM should be clearly signalled but incrementally introduced so as to mitigate material price shocks, maximise stakeholder acceptance and understanding, and avoid risks of unintended consequences; and

9. The analytical foundation for changes to the TPM now or at any time in the future should be comprehensive and robust.

Within the context of these principles, a TPM framework can and should be grounded in practical realities and promote increased efficiency, while also being appropriately adaptable to changing circumstances, familiar to stakeholders, and thus comparatively easy to communicate and manage over time. Would it be perfect? No. Does it need to be perfect? No. Would it be good and self-correcting over time? Yes.

5 Other jurisdictions that adopt forms of beneficiary pays have significant latitude to put benefits into categories, including those that are to be socialised or recovered via postage-stamp or other similar types of charges and those that are localised to particular regions or jurisdictions. Invariably the regionalisation and jurisdictionalisation involve much larger economic zones than the regions identified in New Zealand.

1.7. SUMMARY: THE VANGUARD IS A RISKY PLACE

The 2019IP has raised a number of important and useful issues, and highlighted problems that merit attention, but it has also proposed a more extreme set of overall changes that go beyond what is needed to address the identified issues and opportunities. Taken together as a package, the changes proposed in the 2019IP would put New Zealand in a unique position worldwide in relation to how granularly it would implement transmission pricing in an LMP-based energy-only wholesale market environment at a time when the one thing everyone can agree on is that the future is not going to be much like the past. Is the full scope of change necessary? At this time? No and no. An impactful but moderated approach can achieve all material benefits within a framework that remains familiar, understood, and established.

Having regard to the analysis provided in the 2019IP CBA, and as shown previously in Figure 1, no material benefits are available from radical changes introduced over the next decade. In this context, what could possibly go wrong from adopting the proposed changes in their proposed form, rather than a more moderated set of changes more carefully calibrated to minimise inefficient avoidance behaviour while still signalling long-term avoidable transmission costs on average? Quite a few things, in fact:

- The loss of an important price signal by removing the RCPD charge and moving to full reliance on LMP for both dynamically efficient grid use and generation investment. Avoidance behaviour might be slowed but also made less economically efficient as there would be a likely loss of valuable information about end user response to price and the viability of various available behind-the-meter options. Cost-shifting is not desirable per se, but observable behaviour and investment has value. Markets thrive on information about choices.

- A large shock of short-term wealth transfers due to an insufficient transition, compromising durability;

- Unexpected difficulties implementing (and realising benefits from) a beneficiaries pay approach in practice, potentially leading to delays in transmission projects and higher costs; and

- The level of disputation may not go down, compromising many of the benefits claimed, particularly in relation to beneficiaries, as many transmission projects have wide and diverse benefits such that the incremental “benefit” from more granular or refined cost allocations would not be worth the contentiousness the new process would invite.

The largest benefits are the most analytically contentious, most speculative, and furthest out into the future whilst the costs and disruptions come almost immediately. These benefits arise from a flawed comparison between two extreme scenarios. A much smaller change in the RCPD charge structure would realise the bulk of benefits estimated, thus avoiding uncertain risks associated with pivoting from one extreme to another. In any event one should not place reliance on benefits arising from comparisons of extreme scenarios, as the natural purpose of such comparisons is to make headline points, not nuanced recommendations.

There is no fully unavoidable charge in practice, and so shifting the charge around through varying means (short of doing so randomly each year) will still create incentives for some form of avoidance behaviour based on expectations. Yet these will likely be less well informed than expectations based on a modest but reviewable and reasonably aligned long-term average signal. At least with a modest continuing RCPD type charge, any avoidance behaviour that still occurs aligns with long-term capital rationing at a value no higher than the long-term average cost of transmission expansion.

We agree with the Authority insofar as there is an emerging case for change from the status quo. There is logic to reducing avoidance behaviour to some degree, as well as the possibility of some pragmatic progress in aligning payments to beneficiaries over time.

But what type of solutions or approaches are most appropriate in achieving this? A detailed and comprehensive assessment of feasible options is critical to the robust execution of any policy appraisal. Where the benefits of at least some change are in little doubt (as is the case here), the comparison and critique of different options for change should garner even greater prominence. It is in this respect that the 2019IP analysis falls particularly short.

2. RESPONDING TO CHANGING DYNAMICS

2.1. Overview

Economic theory dictates that pricing of services should be inverse to the elasticity of demand for those services. That is to say, prices should be higher where demand is inelastic (i.e. consumers are less price sensitive) and lower where demand is elastic (i.e. more price sensitive). This pricing strategy, known as Ramsey pricing, provides a more efficient / non-distortionary way of recovering a given revenue requirement. The current concentrated RCPD charge can be seen, at least in part, as such a strategy. It raises prices in peak periods, where demand has traditionally been *inelastic* relative to off-peak periods.

2.2. Increasing Behind-the-Meter Options

Avoidance behaviour challenges the logic of Ramsey pricing, as consumers' increasing ease to switch between peak and off-peak services, means that the two services are becoming more homogeneous and hence the ability to price differentiate across services less sustainable. This is likely to become truer over time, as the costs of avoidance continue to fall.[6] There is a clear divergence from the rail sector in this respect, where rail operators price differentiate to different customer groups through peak and off-peak charging. For rail passengers, the choice of peak or off-peak travel remains essentially distinct, and so the case for price differentiation continues to be strong. For electricity, on the other hand, growing battery adoption means that customers can and will increasingly shift their grid demand from peak to off-peak periods; marked price differentiation in this context is less sustainable. The growing substitutability in electricity may be, at least in part, why the Authority's time-of-use elasticity estimates exhibit less marked differences than one might traditionally expect (an elasticity of -0.49 for distribution-connected demand at peak, compared to -0.55 off-peak).[7]

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6 Such falls occur over time, but only become relevant or material if they cross some tipping point where suddenly options that were not previously commercially viable or attractive to customers now become so. Batteries have been around for over a century, but their applications behind-the-meter for customer load shifting have been very limited due to cost. Maybe sometime over the next decade battery costs will fall, and performance will rise, such that this situation changes. At present, however, batteries are typically only economic in situations where markets have been shifted far outside of normal balance by policy changes that create manifest surplus renewable energy, dropping market prices for a period of time, creating a more attractive charging, discharging cycle than would otherwise exist, or creating a need for faster responding technologies to accommodate intermittency.

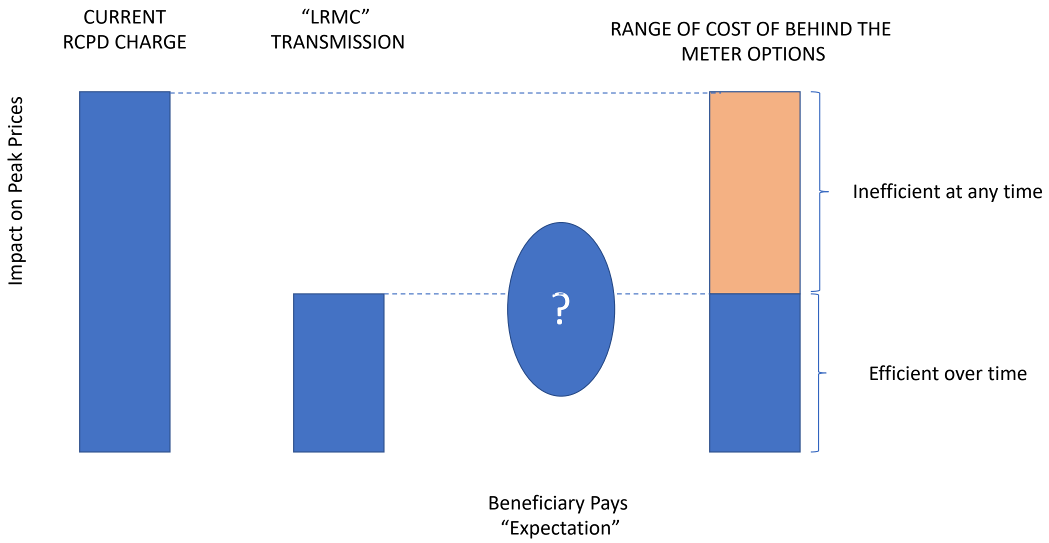
7 A problem with this observation is that any change to peak period elasticity is going to be a function of the RCPD charge. When the charge is too high, then it reduces the cost (increases the attractiveness) of avoidance behaviour during peak periods and makes electricity demand appear to be more elastic than it really is. Accordingly, the use of demand elasticities – particularly during peak periods – requires additional care as the RCPD charge is reduced. This would suggest adopting a somewhat more inelastic demand assumption at peak as the RCPD charge is recalibrated downward.

So, at least from a Ramsey pricing / static efficiency perspective, the case for concentrating transmission cost recovery in relatively few peak periods has diminished and will continue to do so. Consumers have ever more options available to them. Some[8] of these allow avoidance of costs through privately optimal, but potentially socially wasteful investments in behind-the-meter generation and storage. In this setting, it is riskier and potentially uneconomic to plan long-lived fixed assets to serve loads that can so easily, cheaply, and materially be reduced. To the extent there is increasing certainty that the options available to end users will only become more impactful and less expensive, this general point strengthens further.

2.3. Customer Response

The RCPD type charge provides a basis for consumers to make decisions that compete with the wholesale market, on average, over time. Accordingly, the only time *material* issues *may* arise – in theory or in practice – is if the RCPD charge is too high or too low at any point in time relative to the impact of a perfectly set beneficiary charge *expectation*.

Figure 3: RCPD v LRMC v Beneficiary Pays "Expectation"



In the figure above, we plot alternatives for peak (e.g., $/kW) pricing and compare with behind-the-meter alternatives. The portion of the current RCPD charge that is above the "LRMC" transmission corresponds to the orange region of the range of costs of behind the meter options and is problematic because it incentivises behaviors and investments in excess of avoidable costs over time. However, establishing the beneficiary pays "expectation" as an alternative is by no means straightforward. The "beneficiary pays expectation" is a function of both uncertainty around future LMPs arising from the possibility of

8 Many options have been available to many customers or distributors for decades. It can reasonably be assumed that the existence of low cost options over such a long period of time has been or should be (or should have been) considered in any planning or approval and capital investment plan.

delayed transmission investment (leading to higher LMPs) and the possibility that some beneficiaries might pay less if there are lower costs in their particular area for any particular reason and some beneficiaries may pay more. Yet, over time, the range of variation is extraordinarily difficult to estimate – and indeed has not been estimated as part of the CBA or the Authority's analysis of the TPM proposal – all that can be said at this point is that instead of an RCPD type charge (at any level) behind-the-meter investors will lose access to more predictable signal and be exposed even more to a more volatile signal together with the uncertainty of how transmission investment may eventually (or not) mitigate that volatility. This may therefore continue to drive inefficient behind-the-meter investment. In this setting, the figure illustrates that a charge more in line with the LRMC would provide greater certainty along with efficiency.

It is also the case that some degree of avoidance behavior is reasonable and to be expected. In just the same ways that one can ask whether highly volatile spot prices and their implications for risk taking and efficiency of risk management lead to efficient investment without availability of hedges or contracts or gentailer structures or even capacity markets, one can ask if increasing reliance on LMP prices as the dominant transmission investment signaling mechanism (or the dominant transmission alternatives signaling mechanism) is "enough" given long-running debates in New Zealand about the availability and sufficiency of forward prices and hedge instruments; the opacity of gentailer structures; and the concentration of the market overall.

2.4. Simple Response: Recalibrating the RCPD

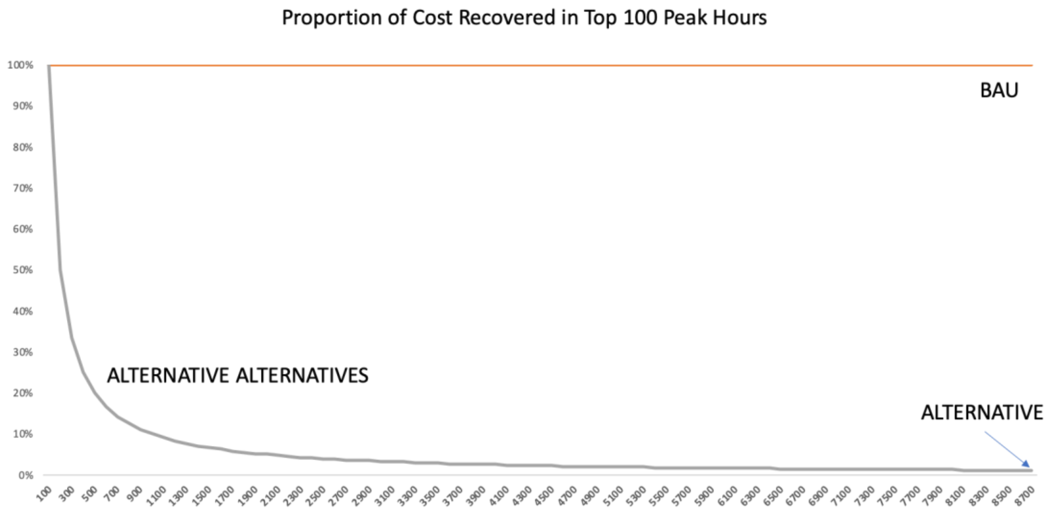
To the extent that, demand-based charges (like the RCPD charge) *are* becoming avoidable at lower costs, then it makes sense to make corresponding adjustments to the RCPD charge itself. It also makes sense to follow such behaviour carefully as it provides a signal as to the availability of options that compete in the longer-term with transmission investment (and cannot be divorced from considering distribution system impacts either, which were excluded from the 2019IP).

Peak demand or other types of potentially "avoidable" costs (like the RCPD charge) therefore constitute both a risk and an opportunity – and they should always be seen in both lights. Clearly, if the RCPD charge is too high or too narrowly focussed, its impact can be too great. But if the RCPD charge is retained and calibrated, it continues to provide a simple signal that elicits valuable information about behind-the-meter supply elasticity (choice). As such, there can be considered to be an optimal amount of avoidance behaviour, one that limits short-term static inefficiency while at the same time still providing information on consumer preferences and choice critical to long-term dynamic efficiency. A charging structure should be designed with these competing interests in mind. Transpower has done much work in this area and would seem to be well-placed to propose an efficient recalibration of the RCPD charge based on long-term avoidable cost estimates.

2.5. Illustrating the Opportunity

A different way to look at this recalibration opportunity is to consider just how much of a difference it makes to recalibrate the RCPD charge simply by spreading it out over more hours. There is more to the required analysis to reach a specific RCPD recalibration recommendation, of course, but Figure 4 highlights how even modest RCPD "base expansion" has a very significant impact on the implied "signal" as compared to the RCPD signal in the top 100 peak hours today.

Figure 4: Recalibrating the RCPD -- Little Changes, Big Impacts



The CBA compared the BAU case with the single alternative (as shown in the far bottom right of Figure 4) in which the RCPD is based on all hours in the year. But there are clearly many "alternative alternatives" with very nearly the same likely impact that retain a modest tilt towards the traditional peak demand periods – in line with more common practice internationally and historically in New Zealand. We think the CBA misses an important and valuable opportunity to focus on the more relevant zone of options, to identify and clarify the dynamics between transmission investment as modelled and behind-the-meter investment as modelled and to highlight the importance of aligning these sensibly and prudently over time. Instead, it is, quite frankly, opaque and confusing.

We accept a case for RCPD adjustment exists; but reject that the CBA supports a specific change – particularly one that is more fundamentally extreme or structurally or philosophically different from current practice.

3. THE (MANY) CHALLENGES OF BENEFICIARY-PAYS

3.1. OVERVIEW

The other key proposition of the 2019IP is that beneficiaries should pay for the investments from which they benefit. Or perhaps more importantly, non-beneficiaries should not have to pay for investments that do not benefit them at all. The logic is simple. Pricing should align social benefits and social costs. If for some consumers the price does not fully reflect the costs imposed on the grid, then they would overconsume grid resources. Aligning social benefits and costs is desirable from an efficiency perspective, but also on the grounds of equity – why should I pay for something that does not benefit me? So, at least from a theoretical standpoint, the argument is straightforward. It is a nirvana we might prefer to the real world we live in. But it is still nirvana. It's not so simple.

3.2. CHALLENGE: EASY CONCEPT; DIFFICULT AND UNCERTAIN IMPLEMENTATION

We can understand and appreciate the interest in beneficiary pays concepts – and have recommended consideration of these concepts as far back as the old "Part F" debates in 2003(!) – but *strictly in the respect of tightening the connection between the approvals process and pricing*.

> *In short, the costs of new transmission investments should be allocated to the beneficiaries of the investment, but only up to the limit of their estimated benefit, since this provides the right signals to grid users of the costs of their actions. If, when applying the economic test to a given investment, it is determined that certain regions or customers are the beneficiaries, then the pricing implications should flow from that. In other words, it should not be necessary so much to have an additional "pricing methodology" for new investments as it is to ensure that the planning and implementation of new investments and the evaluation of the economic benefits are consistent.*
>
> *If there is inconsistency between the estimation and attribution of benefits when applying the economic test and the determination of the prices that customers are to pay, then any process that is adopted cannot be assured of functioning effectively over time. Indeed, any process that depends on input from affected stakeholders to improve the overall economic efficiency of the result inherently assumes that the affected stakeholders are responding to an appropriate set of incentives in the first instance.*[9]

9 E. Grant Read and Michael T. Thomas, "Part F: Operationalising the Commission's Proposal in an Integrated Framework", Public Submission for Meridian Energy Limited, 8 December 2003.

Of course, after 2003, the whole regulatory structure and process went in a different direction, with subsequent reforms and changes such that efficacy of changes required to implement beneficiary pays now depend at least as much on ComCom as on the Authority.

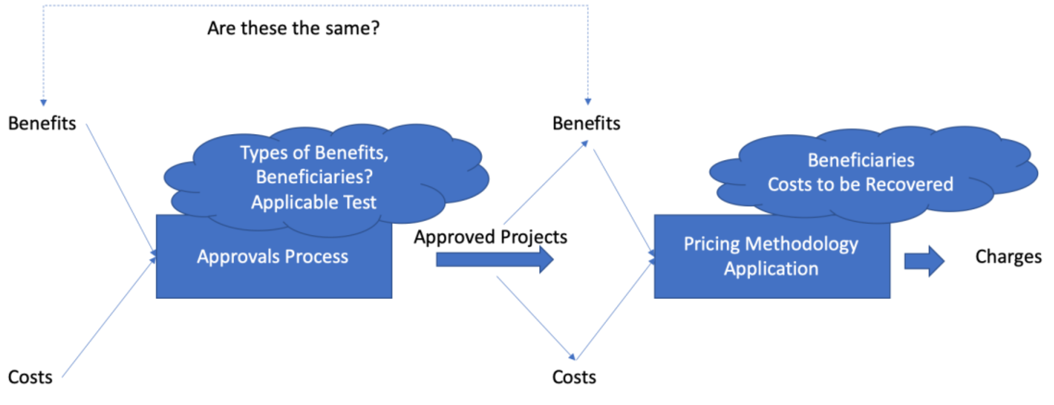
Crucially, the relevant approvals process, itself, must also be clear and comprehensive in relation to how all of the various types of benefits are to be treated, such as reliability, safety, competition, option value/development, and other economic benefits, as each has different potential beneficiaries under different conditions and at different points in time.

3.3. Challenge: Complicated and Split Process

The relay race or assembly line that determines transmission outcomes in New Zealand has many points where there can be material divergence between the way benefits and costs and even beneficiaries are determined in the approvals process and what happens at the pricing stage.

No beneficiary pays type approach can be expected to produce material benefits as a result of "beneficiary" involvement in the process if the process itself is multi-staged with different degrees of involvement, evaluation, and exposure in each stage. The claimed benefits associated with adopting a beneficiary pays approach in the TPM are associated with enhanced stakeholder participation in the process, but these benefits may be unattainable (or even negative) if the process itself has potential inconsistencies, particularly if the process can be bogged down or gamed through free ridership and rent-seeking behaviours.

Figure 5: The Two-Stage Process of Transmission Approval and Pricing



The workings of approval processes and tests are idiosyncratic to each market and reflect the types of benefits deemed to be relevant; the way in which they are calculated; and the policy context that determines how they should be recovered. The challenge does not lie uniquely in any single aspect of the overall process by which the need for transmission is identified, planned, challenged, reviewed, approved, priced and recovered, but in getting that whole process to work coherently and consistently.

The TPM is only one part of that process. There are many “real world” departures from theoretical nirvana unavoidably bound up in New Zealand’s unique combination of LMP, hedge markets, industry structure, system topology, transmission planning, competition dynamics, policy, ownership, and regulation. We caution against moving (too) aggressively towards theoretically interesting solutions when practical alternatives already exist in New Zealand and are more commonplace around the world.

In past decades we have argued that there should be more alignment between the approvals process and application of the grid investment test and any other factor considered and the pricing methodology.

Alignment depends on three things:

- That the process of review and approval will work as intended to attract a representative set of views and inputs from the broad range of beneficiaries and non-beneficiaries (who might be concerned they could be classified as beneficiaries).
- That any resulting material differentiation by region or other factor aligns with broader policy objectives; and
- That any resulting inter-temporal cost recovery issue is acceptable.

All three of these are complicated (and are by no means assured to be achieved reasonably) thus creating a potential gap between what is theoretically desirable and what can be achieved in practice. For example, if a major investment in a region has particularly long-term benefits but front-loaded cost recovery, then the idea of “beneficiaries pay” is confounded by the fact that the beneficiaries are not paying and will not pay – they will get benefits in the future that someone else paid for.

3.4. Challenge: Different Types and Timings of Benefits

We have no problem with the beneficiary pays *concept*, but we see much yet to be done to true up the concept with the practical challenges that go with it. These challenges are made greater in New Zealand by absence of clarity as to what benefits are to be included and how these are to be reconciled – especially between ComCom’s grid investment test and approvals process and the Authority’s pricing methodology. So numerous and challenging are these questions of implementation, that the achievement of a more efficient and/or equitable outcome is far from an inevitability; in doing so, it is likely to raise just as many questions and arguments as it answers and resolves. The 2019IP should be more alive to this reality. A policy statement seems essential to clarify the benefits (and risks) to be considered and how they are to be considered in pricing.

The Authority has expressed concern about durability. In our experience, these are the types of issues that – if resolved or clarified in the initial framework – contribute most to durability.

3.4.1. Challenge: Are All Benefit Types Able to be Defined?

Establishing clear and appropriate benefit categorisations and the level of granularity are crucial to the effectiveness of any beneficiaries-based determination. This cannot be done through the TPM alone. A Government Policy Statement is needed before launching into a meaningful and efficient beneficiary pays regime – one that goes beyond the conceptual assessment provided by the Authority. Otherwise the TPM cannot be evaluated in terms of whether it is consistent with the underlying nature of benefits being considered, or even the process and analyses that were used to approve the investment in the first place (by ComCom). For example, in New York, three broad categories are used, each with different beneficiary determination considerations:

> *(a) For the reliability category, beneficiaries of investments are determined and costs are allocated based on calculating the amount of load that would be shed (without the investment) and who would lose it.*
>
> *(b) For the economic category, beneficiaries of investments are determined and costs are allocated based on decreases in load's payments for energy as a result of a transmission project. The models estimate or forecast changes in locational marginal prices (LMPs) resulting from an investment for each of 11 cost allocation zones over the first ten years that the investment will be in service. For example, New York City is one of the 11 cost allocation zones[10], and Long Island is another.*
>
> *(c) For the public policy category, the PSC specifies the allocation process. If there is no specification, the method defaults to a state-wide load ratio share. For public policy projects considered to date, the PSC has specified a portion of the costs to be shared across the state, with the balance allocated in accordance with NYISO's beneficiaries-pay method for economic investments.*

It is not clear to us whether there is a sufficiently broad and comprehensive available categorisation of benefits so that the treatment of those benefits in both the approvals and pricing stages can be clear and robust. As Transpower and others identified during a recent meeting with market operators and stakeholders in the USA[11], categorisation of benefits is an important element for which detail is lacking in the TPM proposals.

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10 New York City alone is equal to just under two New Zealands.

11 One reason that beneficiaries are relevant in the USA is that most markets now span multiple jurisdictions. Accordingly, it has always been necessary to develop cost sharing approaches for transmission that spans jurisdictions. Perhaps more than any other factor this has shaped the US approach to beneficiary pays over time and results in relatively larger areas of benefit being determined than is proposed in New Zealand. Impacts will also vary with transmission system design and degree of meshing. New Zealand's small size and long-stringy transmission system undoubtedly creates much more granular impact and beneficiary issues than we see more commonly elsewhere.

3.4.2. Challenge: Are Benefit Timing and Incidence Issues Recognised and Resolvable?

We had some experience in an ASEAN country when a pipeline was built to connect a new LNG terminal to the existing pipeline system. The incremental pipeline costs were to be allocated to beneficiaries. Yet who were the beneficiaries? The beneficiaries clearly constituted both present and future users as the pipeline was sized for a projected level requirement that was years away from being realised. What then should be the allocation rule? The pipeline investor (analogous to Transpower) incurred the cost to build a pipeline that might initially be used at only (say) 10 percent of its capacity. If direct users are beneficiaries, do they pay the entire annualised cost or just 10 percent of that cost? Are the costs levelised, or based on rate base return plus depreciation principles? Or are they profiled according to the overall usage projection? Different options leave the developer exposed to sums to be accrued and recovered later or the users with the prospect of having paid a premium for a pipeline their competitors can access later at a lower effective price. Should the regulatory regime allow this? And should rights be associated with the payments made? What happens if usage does *not* grow as expected? If it grows less than expected, then at what point does the uncollected cost need to be collected, and from whom? What flexibility exists to design or implement the additional recovery mechanism, which must be developed after the fact? Would the surcharge be “use based” or recovered through taxes or general revenues or through some unavoidable fixed charge? If demand fails to develop, the failure will be noticed by stakeholders, setting up opportunities for argument and debate over who bears the risk, ex post. Accordingly, principles ideally are determined ex ante.

All of these (types of) questions are relevant to a beneficiary-based scheme; though they are often over-simplified or over-looked until a situation arises in which, surprise, they really matter. Problems then result. In our view, “durability” depends on anticipating and preparing for these to the extent reasonably and practicably possible.

Given the size and lumpiness of transmission investment and the unavoidable links to economic development, it is not possible to identify beneficiaries robustly without considering both location and time, suggesting that a big challenge will emerge with respect to how to sculpt the time profile of cost recovery accordingly. Do the children of current parents ever leave home to get jobs in other parts of New Zealand? Do those possible employers use electricity? About seven percent of New Zealanders move more than 200km’s every five years.[12] The economy is interconnected and interdependent. Yet, the indirect benefits of such interconnectedness and the option value afforded by diversity of economic development are not reflected in any analysis of transmission benefits. Such calculations are fraught with their own interpretative challenges, of course, but the more important point is that any qualitative or quantitative consideration of such omitted factors tends to *broaden*, not narrow, the beneficiaries (direct and indirect) of transmission projects over time. Similarly, decarbonisation policies, industry support

12 http://archive.stats.govt.nz/browse_for_stats/population/Migration/internal-migration/are-nzs-moving-longer-distances.aspx

policies, economic development programmes, and broader competition and reliability considerations also tend to argue against being too narrow or even too prescriptive *ex ante* in defining beneficiaries.

A related challenge of beneficiaries-based schemes is the that the allocation of costs often comes without any allocation of rights. This problem is suggested above in the example about the pipeline investment. Do late comers get to free-ride on the early payers? If the early stakeholders truly derive sufficient benefit to pay for everything now, then *perhaps* that is still efficient compared to the alternative of not investing in a particular transmission project. But what if the analysis of benefits indirectly attributes *future stakeholders* with the future benefits, but does not distinguish future beneficiaries from current ones? Will the analyses undertaken to determine beneficiaries be sufficiently time-sensitive and granular? Or will it be more generalised?

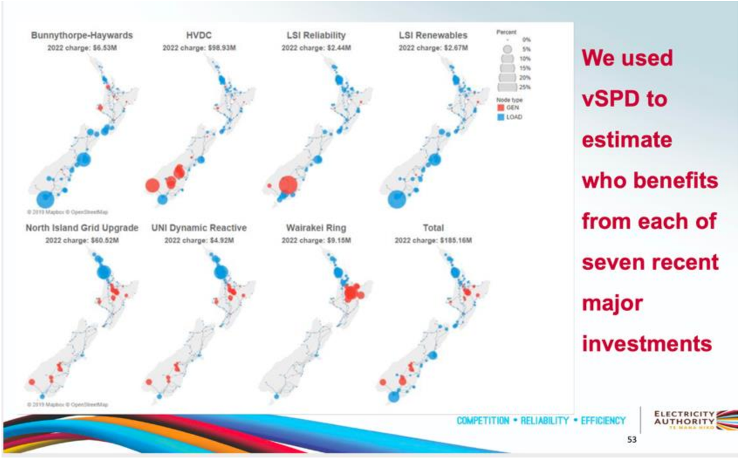
If it was once determined that certain (types of) benefits were likely but then later they do not occur, are the associated costs to be covered only by the now unlucky non-beneficiaries? Was it really up to them? Or was the decision made on their behalf? What if the reason the benefits were not realised is that there was a change in government policy? For example, what if certain benefits do not arise due to a change in government policy pertaining to decarbonisation, economic development, or electric vehicle usage?

A framework is needed – complete with whatever reasonable compromises are required. Leaving these matters open ended, however, undermines the value of beneficiary-pays and argues against implementation at this time.

3.4.3. Challenge: Materiality

The work done by the Authority to date on the various legacy projects highlights the broad nature of many of the benefits measured, as shown in Figure 6. Whereas some projects clearly have more localised benefits, most have wide-spread impacts, raising the question of whether a full-blown beneficiary pays allocation is necessary or appropriate for projects with a wide enough set of impacts.

Figure 6: Seven Legacy Projects and their Impact



We agree with the 2019IP insofar as there is <u>no compelling economic efficiency</u> case to reallocate the costs of the seven recent major investments that the 2019IP has suggested to bring under the beneficiary-pays regime. Moreover, the 2019IP analysis shows that the beneficiaries of these investments, when considered in aggregate, are spread rather broadly and evenly across the country (covering both North and South Island), with no clear case to suggest that the benefits are accruing disproportionately to a small group of customers in a given area. With this in mind and given the major limitations in implementing a benefits-based approach described earlier, there is not a definitively strong case for altering the charges applied to these legacy investments. With the broad spread of benefits observed, a much simpler modification of the current RCPD approach for recovering these costs is likely to achieve the same outcome.

The 2019IP also justifies the proposed approach to legacy investments on durability grounds, but here we also disagree. Commitments should be firm, but they should also be efficient. When there is a strong value case to reopen something, one can expect the reopening to occur in the commercial world. When reopening something is merely arbitrary, doing so casts aspersions on the value of commitment. What value is there to a commitment or promise or agreement, or contract, or policy if it can be undermined on an arbitrary basis. Stakeholders make long-term decisions in part based on their assessments of the scope for change. If commitment is weak, then logically the decisions stakeholders make will evolve to reflect that, compromising value over time.

We note that the Authority's analysis does not suggest material trapped value can be released by revisiting the legacy projects. The argument instead is merely one of durability by making a change to honour a new principle. In our view, switching principles *undermines* durability. It is signalling that tomorrow there may be yet another principle that can be used to review today's agreement. Unless there is material value or market distortion being fixed or a change to actually implement what was previously agreed, we would not normally see a case for changing the way a legacy asset is treated in a regulatory context.

Additionally, the Authority's CBA assigns benefits to the use of beneficiary pays based on the idea that some savings relative to the current approvals process is likely. For projects with *wide and diverse benefits*, we challenge that assumption and argue that if there are enough beneficiaries spread over enough regions, the shift to beneficiary pays is a shift to a noisier but not necessarily better debate than what could otherwise be achieved. It is only a *subset* of projects – those with almost certain non-beneficiaries – which might be resolved more equitably and potentially efficiently though a more focussed cost recovery framework.

3.4.4. Challenge: HVDC

In the case of HVDC assets, however, we consider that there *is* sufficient justification to intervene. The current charging structure clearly distorts efficient investment decisions, by imposing all charges on South Island generation. This is clearly a situation where the cost recovery (pricing) mechanism is inconsistent with everything else, for reasons that have no economic grounding other than historical practice. Yet even historical practice has flip-flopped over decades from a beneficiary pays style approach splitting recovery across both generation and loads on both Islands to the current arrangement which bears no resemblance to any current or proposed methodology.

Recognising the contentiousness of the issue, the long years of dispute and frustration, and the obvious economic distortion of the present arrangement, we advise an overarching principle of simplicity. Accordingly, one such approach is to recover the associated HVDC costs through a simple $/MWh charge applied to all North and South Island generators. This approach resolves the fundamental economic efficiency concerns around generation location decisions, by allocating charges across both North and South Island generators. For a number of reasons, we do not consider it sensible to look beyond this, for example, to a charge across all North and South Island generation and load. Our advised approach already corrects for the (undeniable) inefficiency in the current arrangements, without having to tackle inherently more complex questions akin to those in a beneficiary-pays approach, for which there is as yet no comprehensive framework in place. As such, given the extent to which these assets have already depreciated, it does not seem proportionate to redistribute these charges any further than we have recommended, as we would quickly run into diminishing returns and likely net costs due to tricky questions around implementation and who bears the costs.

3.5. Challenge: What Next?

The 2019IP proposes shifting to a beneficiary-pays approach, in place of the current RCPD and HVDC charges. It considers that there are benefits to adopting such an approach, but without sufficient clarity on how this would be implemented these benefits are likely to be elusive or even negative.

The proposal advanced to date is based on an assumption that more focussed beneficiary “participation” in the overall transmission investment approval process is likely to create value. It assumes every project and proposal is analysed within a beneficiary framework. But, as we have discussed earlier, this by no means needs to be the case.

In particular, the 2019IP’s main focus in thinking about beneficiary pays with respect to the existing TPM is that it is possible to identify comparatively extreme examples where significant non-beneficiaries appear to exist. The other side of that story, however, is that one must consider the possibility that opening up the cost recovery allocations for all the projects that have broader benefits is just as likely to spawn new disputes and arguments over how and where and even when to calculate a cost recovery obligation on various stakeholders.

These issues cannot be resolved without a fully coherent framework, the absence of which should be deeply concerning to the Authority and all stakeholders. Without a suitable framework, there will be additional costs associated with moving to a theoretically more efficient framework but one whose implementation is incoherently structured and thus (even) more prone to argument. Let there be no doubt that once unbound from the current simple allocation methodology, stakeholders will argue vociferously, using combinations of signal and noise, with rent-seeking and rent-rejecting activities that will be hard to disentangle. The 2019IP does not appear to have considered these costs of disputation and how it varies depending on the extent and spread of benefits. Many projects would simply not benefit from more focussed consideration beyond what is normally done.

We further note that the comparatively small size of New Zealand (in terms of both economy and population) means that potential different transmission cost recovery regions are already far smaller than their equivalents in other markets which practice some variant of beneficiary-based cost allocation. The upshot is that, under the 2019IP proposal, New Zealand would be pushing the vanguard in terms of granularity of cost allocation, and thus inviting far more disputes than might otherwise have been the case. Is this really necessary to achieve material improvement – most of which is bound up in simple modifications to the RCPD charge?

With all these complications to what might otherwise seem a simple sounding and appealing concept, the value of strict adoption of a beneficiary pays approach becomes much less clear. It very much feels like there is a major piece missing between the high level and less contentious conceptual statement that a system based on beneficiary pays is logically sensible, and the practical difficulties and confounding implications of actually implementing a particular approach.

In our view, it would be simpler to consider a default approach that involves similar treatment to what is done at present and to exercise the beneficiary-based approach by exception using various guidelines and standards. This allows Transpower to undertake an initial screen to establish whether a project is a candidate for the default treatment or requires additional analysis. In those (likely numerous) cases where benefits are already clearly broadly based, the default approach would be employed for simplicity and dispute avoidance. Those that require additional analysis would be subjected to more detailed review, reducing the number of projects and the amount of work involved. Accordingly, the process should become simpler and more focussed – two prerequisites that we believe must be met in order that the types of scrutiny benefits suggested in the 2019IP can even hope to exist and be realised.

To ensure the smoothness, transparency and credibility of this process, guidelines would be required. For example, an investment that, in screening, impacts fewer than, say, 40% of stakeholders could be flagged as a candidate for a more detailed beneficiary pays consideration because the debate is likely to be more focussed and there is a real material cross subsidy to be avoided. As almost every region will have such an investment from time to time, the net impact over time should be relatively comparable, but at least for those particular investments there is a case to be made for a more focussed set of stakeholders to weigh in disproportionately on whether the project(s) are appropriate. On the flipside, investments that touch, say, 60% or more stakeholders with impacts on both islands could be automatically handled by the default approach. Any project in between might be reviewed in terms of the nature of the benefits, timing, and other considerations before being assigned to the default or beneficiary approach.

None of this is ready to be implemented at this point, however. Before being able to accurately assess projects in this way, there must first be agreement as to the nature of the benefits that are being evaluated. A Government Policy Statement is needed to provide clarity on this. Otherwise, what is the point of adopting a beneficiary pays approach if one is not actually able to consider all the possible types of benefits in a holistic way, and must assess benefits that can be identified without guidance as to how to handle risk, inter-temporal impacts or other issues. A policy statement would provide useful and timely guidance as to how to treat the myriad of special and diverse cases likely to arise in adopting a beneficiary-pays system. By doing so, this would avoid the risk that ComCom will approve things on one basis and the Authority will endeavour to recover costs on another.

And so we have to ask, does the Authority's approach really meet its statutory objective? When you get into the details for the framework and the implications of the proposed implementation, we conclude that there remain a number of issues that need to be resolved before reaching a beneficiary pays proposal that "hits the mark."

We consider that, of all the elements in play in the proposed TPM, the implementation of a beneficiary pays approach is the least fully developed and would benefit from significant enhancement and clarification.

Notwithstanding the above serious concerns, there may yet be a desirable beneficiary-pays based approach and associated process that remain to be developed, just not that which has been proposed to date. The proposed approach is incomplete and excessively complex and granular for a small country like New Zealand. There is much more work needed to clarify the benefits and how they are to be treated; simplify the administration where possible to reduce costly delays and “noise filled” disputation; and focus the delineation of beneficiaries and how they should be charged for projects that clearly touch a subset of stakeholders.

4. LMP VS RCPD

4.1. Overview

The 2019IP takes the position that the use of LMP in New Zealand provides sufficient cost signals for managing congestion and grid use. This is in notable contrast to the Authority's position four years ago:[13]

> *'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.'*

We understand the theoretical logic advanced in the 2019IP, but disagree that the theory should be implemented in New Zealand as suggested by the Authority. New Zealand may be paradise, but not even New Zealand is nirvana.

4.2. Challenge: LMPs

While LMPs are calculated in New Zealand, it is not the case that the values calculated automatically have all of the properties that an LMP is theoretically supposed to have under the conditions where you can rely on LMPs as a stand-in for any other form of transmission charge.

- First, LMP *is* only short-term in nature and amounts to a volatile competitive market price signal often without a corresponding long-term contractual hedge available.
- Second, the New Zealand market is small with workable competition at best. The transmission network is long and stringy with many implications for competition and reliability and relatively fewer projects that would be dominated by economic considerations.
- Third, New Zealand is committed to decarbonisation which automatically infuses all planning scenarios and stakeholder expectations with the likelihood or even inevitability of future policy intervention or guidance to assure achievement – with likely implications for transmission development that go beyond LMP considerations.
- Fourth, the wholesale market itself has been subject to numerous reviews – some quite deep and wide-ranging – canvassing market structure, market power, hedge market performance, hydro management, dry year reserve policy, and retail pricing. LMPs may be technically mature in New Zealand, but the market is no more insulated from broader forces and factors than any other.

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

- Fifth, many, if not most, of Transpower's proposals will have a significant "reliability" or other benefits component. Little of these benefits will have much to do with LMPs, though the projects may of course affect LMPs. To the extent such investments occur, they should manifest themselves through broad based charges not unlike a recalibrated RCPD charge suggesting that an RCPD type charge would be better than LMP at incentivising competition from possible alternatives more efficiently.

None of these broader considerations fit neatly in the efficient market model – they are, however, practical factors that stakeholders must try to anticipate and balance. Neither the LMP side of that equation, nor the beneficiary pays part of that equation are perfect enough to move entirely away from an RCPD-type charge.

4.3. Challenge: Attributing Benefit to Beneficiary Participation

Identifying beneficiaries *using input from the potential or prospective beneficiaries themselves* is beset with the challenges of overcoming free ridership, public good, and the associated 'tragedy of the commons' problems. Accordingly, most markets, including New Zealand, have adopted some degree of centralization with various processes and tests to determine what transmission projects should be approved and developed. Most have also adopted simplifications to treat certain categories of benefits differently, or to use larger regions within which benefits are attributed, or to limit the involvement of beneficiaries to those areas where it is most clear that reasonable lines exist between beneficiaries and non-beneficiaries.

Even the work done to date on the various legacy projects highlights that for every individual project that has some material beneficiary specific distribution of benefits, the collection (and several of the individual projects) have such diverse benefits that one can reasonably ask why is it not better to use simpler rules to filter and screen out those projects likely to have multi regional, multi-island, complex inter-temporal benefits and look for simpler rules, and limit the more detailed beneficiary analysis to more specific questions. If the Authority is looking for a more durable principle, then focusing analysis on things that really matter has got to be an upper most consideration.

The idea of marrying beneficiary pays and LMP goes back a long way and has always been fraught. It was one of the earliest proposals for the New Zealand market going back to around 1989, even, or before. The idea, then, was that there would be full nodal pricing with financial transmission rights. New investment would occur if, and perhaps only if, a beneficiary coalition agreed to pay for it (and accept FTRs in return). However, this original pricing and investment recovery framework struggled because it was impossible and impracticable for beneficiaries to form (or be formed into) sufficient, robust coalitions to pay for new projects. Additionally, FTRs have always been a little complicated in the smaller, less liquid, New Zealand context. The existence of complex intertemporal effects (someone pays now for benefits to someone else later) for which it is difficult to reconcile also complicate matters. Delays in transmission projects tend to remind stakeholders that not all transmission benefits are captured in nodal price differences and that even when benefits appear plausible and material, beneficiaries are not especially inclined to agree and cooperate.

There was not then, and still is not now, a sufficient mechanism in the New Zealand context with which to establish a long-term benefit associated with being a beneficiary who pays for transmission. Nor is there an instrument proposed by the Authority by which beneficiaries who are charged for transmission augmentations gain any particular rights (or exclude those who do not pay for the rights). There is nothing about the proposed beneficiary pays or LMP reliance arrangement that enforces discipline on revelation of preferences as is important when assessing beneficiaries given the temptations of free-riding and rent-seeking. These, too, are departures from the competitive ideal model in which LMPs play the role envisaged by the Authority.

4.4. Challenge: Dynamic Efficiency

The New Zealand market is small and moderately concentrated. Workable competition is essential to the overall efficiency of the electricity market. Dynamic efficiency has been a focal point. Maximisation of static efficiency has been discounted on the grounds that entry and exit and innovation and change are much more important value drivers over time than narrowly defined asset optimisation in the short term, and that efforts to maximise static efficiency may impair dynamic efficiency. Simulation models are especially problematic when assessing dynamic efficiency as dynamism tends to introduce more change than might otherwise have been expected. Outguessing markets is tough to do.

As an economic mechanism, the New Zealand wholesale market works well enough on balance and even extremely well most of the time; nonetheless, it has also been the subject of periodic deep reviews for concerns about competition, market power, liquidity of hedging, and such.

In that context, what we know is this: fully removing the RCPD charge would eliminate a simple, effective, long-term signal that contributes to competition in the otherwise thinly traded market. What we don't know is just how well the Authority's proposed alternative approach in which there is no RCPD charge would work, except in theory.

Just stepping back and looking at New Zealand from an outside perspective, it seems odd and problematic to propose removing a charge that (when calibrated) increases competitive pressures, even if imperfectly, in favour of removing the RCPD entirely and relying even more on a wholesale spot market that is, at best, just workably competitive on average over time and is frequently under review for the possibility of market power. Not to mention a market that has endured transmission pricing uncertainty for the better part of 15 years.

4.5. Summary

If end users or those that retail or distribute to them see a sustained but reasonably long-term cost-aligned signal, they can plan and execute reasonable, predictable, equivalently cost-aligned responses. Projections of demand upon which plans of transmission investment are premised would be more robust.

Reliance on underlying nodal prices would otherwise be challenging, as periodically high or spiky nodal prices or even extended periods of shortage pricing are invariably problematic. Would transmission projects be suitably delayed so as to allow optimal determination of behind-the-meter investments? Would projects be advanced for reliability or other reasons (or would the analysis be tilted or biased given that building transmission is exactly what a transmission asset owner would want to do)? If resulting LMPs are correspondingly depressed relative to their "optimal" level, who would know? How certain is it that the participation of beneficiaries – given the challenges inherent in eliciting or filtering out accurate signals from vociferous stakeholders especially at a more granular level – would be perfect enough to overcome these issues?

If the transmission evaluation and approvals process incorporates (as it should) factors other than just LMP differences when evaluating transmission projects, the impact on LMPs will be broadly depressive on average, but the costs to be recovered from stakeholders would increase. Such a result confounds the process of determining whether behind-the-meter alternatives are appropriate or economic, as it becomes more difficult for customers to evaluate whether such investments are preferable in terms of the grid charges it allows them to avoid.

The longer term dynamic efficiency of grid-side generation and transmission and storage competing with behind-the-meter generation and storage *will be inefficient* without a reasonably calibrated peak demand (RCPD) signal <u>unless</u>: (1) the transmission planning and approvals process; (2) the beneficiary pays cost recovery arrangements; (3) the underlying LMPs and wholesale market pricing arrangements in general; and (4) the overall policy environment and how it interacts with the electricity sector are collectively broadly perfect enough.

We don't think that burden has been met anywhere, even in New Zealand.

5. THE CBA

The 2019IP CBA can in effect be thought of as a two-stage process. The first stage considers the causal pathways, or mechanisms, by which the proposed reforms impact the market. The intervention is, for example, theorised to improve grid use efficiency and increase scrutiny on investment proposals. The second stage is then, where possible, to assign a quantification to these identified costs and benefits. A CBA can therefore breakdown at one or both of these stages: in the former, for example, through a failure to consider a comprehensive set of mechanistic impacts, or else to reason illogically the expected impacts; and, in the latter, through say an unfounded assumption or modelling error that does not accurately reflect market reality. It is within this framework that the credibility and robustness of the CBA can be assessed.

The CBA quantifies several different costs and benefits. However, the overall net benefit really boils down to the benefits of more efficient grid use, comprising over 95% ($2.6bn) of the estimated net benefit. Other material components are the benefit of more efficient battery investment (7.5%), and the cost of grid investment brought forward (which forms part of the more efficient grid use modelling). These are the CBA components that warrant focus in this high-level critique.

5.1. BIG DIFFERENCE IN; BIG DIFFERENCE OUT

Before looking at key components of the estimated net benefit, it is first critical to recognise that, in the case of the Authority's CBA, we start with an RCPD charge that is too high. Thus, in one scenario we have business-as-usual with a highly concentrated RCPD charge that is clearly well above the cost corresponding to long-run average transmission cost. In the other main scenario, we have a situation where the charge is completely flattened out and recovered over all periods. Of course, the results of this particular comparison are going to be skewed by how the underlying model responds to the relative cost of investments with the well-above-cost RCPD charge versus the well-below-cost RCPD charge. Big difference in; big difference out. Accordingly, we would want to see much more detailed interrogation and analysis around the so-called relevant middle area – where the questions are more interesting and options more relevant. This relevant middle analysis is what is missing in the existing CBA. The Authority's scenario analysing the impact of a modified RCPD charge is much more interesting and achieves the vast majority of the benefits (as would be expected) the Authority deems available.

Put differently, if prospective transmission augmentation and expansion costs are less costly per kW than the RCPD charge that is triggering avoidance activity, then the most likely outcome will be more expensive avoidance activity which will in turn delay less expensive transmission investment. Where past studies or analysts have been more dismissive of grid use benefits, we suggest it is because they were not inclined to use an extreme argument to make a nuanced point. An extreme argument or demonstration calculation may well assist in illustrating the case for "change", but it does not similarly inform a debate about the best specific form of change.

5.2. More Efficient Grid Use

This is the single biggest quantified benefit of the CBA. The results and efforts represent a stark change from the CBA which accompanied the Authority's Second Issues Paper, for which the benefits of more efficient grid use were not quantified because "they were considered to be minor". In our view, this was (and is) an appropriate assessment when undertaking a CBA of options that do not involve a comparison of wide extreme cases.

In this context, the first question that springs to mind is what has changed for the Authority to expect that their proposal would deliver material benefits in grid use efficiency? In other words, why is it that the Authority now considers that the removal of the RCPD charge will have a material enough effect on grid use efficiency that warrants its quantification (something considered unnecessary only three years earlier)?

At some risk of repetition, one reason why grid use benefits are generally much smaller (or not considered at all) – despite their being a focus in the Authority's CBA – is that in order to calculate benefits of the magnitude found in the Authority's CBA, the scenarios being compared must be very different.[14] The extent of difference allows other modelling simplifications and assumptions to operate over a thirty-year time frame without the full complement of push/pull responses that invariably emerge over time in the real world.

The results obtained are indeed very different. It is simply not prudent to rely on the modelling of two extreme scenarios except to establish – *maybe* – bookend values to make a broader or high-level point. Anything that requires a more nuanced assessment needs to be evaluated using a more nuanced set of differences in scenario definition and assumptions – and needs to be evaluated using a set of additional criteria that assist in differentiating the options available on as many grounds as might be relevant to the decision required.

5.2.1. How Does the 2019IP Establish that Grid Use Will Be More Efficient?

The 2019IP directs significant focus on the point that LMPs already provide all the necessary signals for guiding efficient grid use, and therefore that an LRMC charge (which could look something like the current RCPD charge) is not necessary. We can see how this might be true in certain perfect conditions; however, the conditions required for LMPs alone to be robustly sufficient do not apply in NZ (nor in any market as far as we can tell).

The effectiveness of price signals to motivate or incentivise or support efficient behaviours depends on the absence of material market failure. A small market in which most investment decisions are also correspondingly small may meet that condition. But transmission projects are often larger and lumpier and are justified for reasons that

14 Setting aside specific challenges to assumptions, treatment of wealth transfers versus benefits, and so forth – all of which become particularly problematic when a framework focusses on comparing two extremely different cases over very long periods of time.

extend beyond merely LMP differences. As such, the impact of transmission investments once approved and built is necessarily disproportionate and depressive. Market prices will always be lower if transmission projects augment capacity for reasons other than LMP differentials. Market prices will also be lower to the extent that it is necessary to invest ahead of full demand because of scale or scope given the lumpy nature of transmission projects. Accordingly, in any quasi competitive market simulation, such impactful investments would not ever be made unless they are supported by a corresponding long-term contract. The RCPD charge acts like such a contract. It is also a signal, which has value because LMPs will not be sufficient and beneficiaries will be too diverse and uncertain in all or even most transmission investment cases.

Overall, the 2019IP CBA assumption that LMPs are now sufficient and can be relied on wholly for all energy related usage and investment signalling is a very strong assumption that has only limited, conditional support, in theory, and yet is proposed to be given prominence in informing the Authority's choice of options.[15] We think this is a mistake. Even if the theory is supportive under certain conditions, the change has not been strongly supported in practice.

5.2.2. Elasticities of Demand

Key to the issue of avoidability is the responsiveness of consumers to changes in price. More price sensitive consumers will exhibit more avoidance (cost-shifting) behaviour where prices are high. As such, the estimation of elasticities is critical to the quantification of wasteful avoidance behaviour that the 2019IP considers to prevail under the status quo of the RCPD charge.

The 2019IP estimates aggregate transmission and distribution elasticities, as well as time of use elasticities, and using this information estimates that the removal of the RCPD charge would result in a 75MW increase in peak demand. This is the initial driver which kicks starts a number of responses in the wholesale energy market: the increase in peak demand raises wholesale prices, which in turn incentivises and brings forward investment in new generation, and which ultimately feeds back to depress wholesale prices in the long-run. Therefore, given that the elasticities govern the magnitude of the initial demand response, it is crucial that these elasticities are estimated accurately. And though in this respect there are some potential concerns with the underlying calculation (for example, elasticities being modelled with respect to wholesale prices, not retail prices), there is a more fundamental question of whether the price elasticity estimates, robustly calculated or not, are informative when the starting point is a scenario in which prices have been 'too high' (due to the RCPD charge) for a long period of time.

15 We have noted already earlier that this contradicts an earlier position taken by the Authority in its TPM Options Working Paper.

The other issue is that with some avoidance behaviour emerging, we can expect peak demand elasticity to become more elastic, but only to the extent that RCPD type charges are too high. According a future in which the RCPD type charge is lower with the same level of potential avoidance (and thus elasticity) as in the past (with a higher RCPD charge) would bias identified benefits upwards. Simply fixing the RCPD charge by bringing it down to a more appropriate long-term level would very likely also reduce elasticities at peak (make them more inelastic), thus reducing estimated benefits as well.

5.2.3. Confusing Consumer Welfare Effects

The 2019IP utilises the estimated demand elasticities to quantify consumer welfare gains: through the traditional consumer surplus approach; and through the theoretically more desirable, though practically difficult, compensating variation approach. It does so to capture the 'full set' of consumer welfare gains derived through the second order effects on the wholesale market.

What is interesting from this analysis is that, if purely focused on estimating the consumer surplus generated by the fall in peak transmission charges (and thus abstracting from subsequent impacts on the wholesale market), then the estimated consumer surplus is materially lower. A net present value in the order $50mn, compared to the total estimated efficient grid use benefits of $2.6bn. The upshot is that the <u>vast majority</u> of the 2019IP's estimated benefits accrue not directly from the removal of the RCPD charge, but rather from the knock-on effect this has for the differential generation investment this stimulates. These effects flow only from the extreme difference between the two main scenarios evaluated in the CBA and from the reason we have already identified concerning the high RCPD charge in the business-as-usual case.

Accordingly, we strongly urge that the main focus omit the grid use benefits. We do not place any credibility on the grid use benefits beyond being a measure of the extent to which the existing RCPD charge is well above the long-term avoided cost of transmission.

5.3. Investment in Grid-Connected Generation

The CBA makes a big point of quantifying the impacts that the rise in wholesale peak prices has on investment generation, and the benefits this in turn brings about in terms of lower electricity prices in the longer-term. However, in spite of this, the CBA does not actually capture the costs of these new generation investments, on the grounds that "the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal is assumed to be efficient investment". While we agree that in a competitive market it can be assumed that investment is efficient, we do not concur that this means that the costs can simply not be taken into account.

A competitive market should indeed ensure that investments only go ahead if they recover their costs, but the materiality of any net benefit generated as a result of this investment depends on much more than whether or not the market is competitive. The investment could allow consumers to use more energy at lower cost, with the price responsiveness of load (the shape of market demand) influencing the magnitude of welfare gains this generates. It is still then necessary to net off the initial cost of investment from this estimated benefit to reflect on the net benefit to New Zealand overall. Accounting for this would unambiguously reduce the size of the 2019IP's estimated benefit.

5.4. Investment in Distributed Energy Resources (Batteries)

The 2019IP considers that the proposal would reduce inefficient investment in distributed energy resources (DER) that occurs purely for the purpose of avoiding the artificially high peak transmission charge due to the presence of the RCPD charge. As it explains, these are those investments which are cheaper than peak transmission prices inclusive of the RCPD charge, but more expensive than peak transmission prices exclusive of the RCPD charge.

The 2019IP models customer investment in batteries by considering their profitability relative to their long run marginal cost, with profits being driven by two potential strategies: through an arbitrage strategy of battery charging when prices are low and discharging when prices are high; and through a peak avoidance strategy to avoid RCPD charges. Under the status quo, consumers are assumed to adopt both strategies, and in this scenario the 2019IP predicts that battery investment would reach over 3,000MW over the course of the modelling period. This compares to only 800MW under the proposal, where battery investment is purely driven by arbitrage opportunities.

The first point to note here is that over 3,000MW investment in batteries under the status quo appears high in the context of the total New Zealand electricity market, which had an installed capacity of 9,237MW in December 2018.

The 2019IP's model assumes an investment ceiling to account for the fact that peak avoidance and arbitrage benefits would decline as battery investment grows. However, this assumption may not be sufficiently restrictive insofar as the large investment in batteries predicted by the model shifts peak demand to the shoulder period, which would in turn attract the RCPD charges. Instead, battery investment should help serve to levelise grid demand across peak, shoulder and off-peak periods in order to maximise price arbitrage opportunities and minimise exposure to peak (RCPD) charges. As such, battery investment to reduce current peak demand should not occur beyond the point that it starts to create a new peak in the previous shoulder period. In theory, at this point, battery investment and usage should be aimed at reducing peak and shoulder demand concurrently through greater charging in off-peak periods (in order to move towards more levelized demand across all three periods). Such dynamics are not captured in the 2019IP modelling.

Given that the modelled >3,000MW increase in batteries would lead to shoulder demand *significantly above* peak demand, then at least for now we can say qualitatively that battery investment must be materially lower than this under the modelled status quo. In effect, the Authority model is overestimating battery investment by failing to account for the dynamics of the situation, whereby the benefits of battery investment decline as the total capacity of batteries in the market increases.

Accordingly, we believe that the benefits of more efficient investment in batteries, estimated by the Authority to be $202million in the central case, to be significantly overstated.

5.5. Missing Risk Framework

Specific benefits to one side, critically neither the CBA nor the Authority's report fully addressed the question of risks or unintended consequences or even other relevant evaluation criteria. Perhaps most importantly in this respect, it failed to consider the risks around pure dependency on LMP pricing, simply suggesting that it seems to be theoretically sound and has a degree of endorsement from Professor Hogan. One would still expect to see a robust consideration of risks – in detail – given that the New Zealand market is small compared to most internationally, and amongst the smallest, if not the smallest, energy-only market with LMP. One might even go so far as to say that a consideration of risks should be the *primary focus activity* given the small size of the New Zealand market and the relatively crucial role that the transmission system plays up and down the North and South Islands.

When undertaking a CBA of the form that the Authority has developed in which the starting point "business-as-usual" option is fatally flawed from the start, the benefit quantum identified soon stops being important. There is enough evidence based on comparison to Transpower's estimates of long-run average transmission costs that the existing RCPD charges are too high during peak hours. The next stage of the analysis really should involve drilling down into specific alternative options that are much closer in terms of overall impact and comparing them against a different and more nuanced set of criteria. One option might have a slightly higher net benefit but different risk or implementation characteristics and so forth.

While a more comprehensive set of outcomes can and should be defined, it is useful at least as a starting point to think of two core dimensions to a new framework. First, some measure (ideally quantifiable) of net benefits, which has been undertaken. And, second, a comprehensive assessment of risks, absent to any reasonable degree in the 2019IP. This is well accepted best practice, with the NZ Treasury itself recommending such an approach in its 'Best Practice Impact Analysis' guidance. It recommends that risk assessment should comprise some form of sensitivity or scenario analysis, as well as a qualitative consideration of risks and uncertainties. While the 2019IP CBA does undertake some sensitivity analysis, it is lacking in comprehensiveness and a qualitative consideration of other risk factors is largely absent.

The concept of risk under any new framework should be defined relatively broadly. In a sense, it should be seen as a catch-all for any issues that fall outside the much narrower process of putting numbers to quantifiable costs and benefits. It should, for instance, capture the implications of a loss of flexibility and the potential problems of committing to too much too soon, as well as uncertainty around what state of the world we are in and what states of the world we are likely to be in in the future. It is in a much more comprehensive framework like this, that more nuanced 'middle ground' alternatives that lie between the current TPM and the Authority's proposal should be evaluated.