Meridian Energy Cross-submission
Transmission Pricing Review: 2019 Issues Paper

31 October 2019

This cross-submission by Meridian Energy Limited (**Meridian**) responds to the submissions on the Electricity Authority's "2019 Issues Paper: Transmission Pricing Review" dated 23 July 2019 (**2019 Issues Paper**).

This cross-submission addresses the key themes from submissions and is divided into the following Parts:

- Part A: Executive Summary
- Part B: The HVDC charge
- Part C: The benefit-based charge
- Part D: The Authority's cost-benefit analysis
- Part E: Consistency with climate change objectives
- Part F: Process for the development of the Transmission Pricing Methodology
- Part G: Attachments
    - NERA Economic Consulting *2019 transmission pricing review – review of certain economic reports* (**NERA Report**);
    - Professor Stephen Littlechild *Comment on two items arising from the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review* (**Stephen Littlechild Report**).

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Part A: Executive Summary

The submissions on this latest round of consultation indicate general agreement that there are problems with the current Transmission Pricing Methodology (TPM) requiring reform. This is consistent with Meridian's long-held view that there are intractable problems with the efficiency, durability and fairness of the current TPM.

These problems are acute in respect of charging for the HVDC. There is broad agreement by submitters regarding problems with the current HVDC charge. A range of alternative proposals for the HVDC charge have been raised by submitters. However, these alternatives are not demonstrably better than the Authority's proposal. The submissions do not present a compelling analysis, and they instead reflect each submitter's private interests. In these circumstances, there is a clear mandate for the Authority to approve a new TPM to correct the problems with the current HVDC charge. This should be a minimum requirement for any solution the Authority progresses.

Meridian strongly supports the proposed Guidelines including the benefit-based charge and the Authority's Schedule 1 determination of beneficiaries for the seven identified pre-2019 assets. Some submitters question the inclusion of existing assets in the benefit-based charge. The attached report from Professor Stephen Littlechild sets out why the latest objections to including existing assets in the benefit-based charge are not compelling. Professor Littlechild elaborates on his earlier analysis that these assets should be included in the (now) benefit-based charge including because as a result of doing so, "investors would see a regulator confidently and competently adapting to a more competitive market".[1] NERA's analysis is similarly that "there are dynamic, productive and allocative efficiency reasons for altering the regime on existing grid assets."[2]

Those opposed to TPM reform have asserted there are errors in the Authority's cost-benefit analysis (CBA). Meridian asked NERA to review the criticisms of the CBA contained in expert reports submitted in this round of consultation. The attached NERA report doubts the validity of many of the criticisms but finds that even if they are made out (which we do not think they are), the CBA nevertheless indicates a significant quantified net benefit.[3] The criticisms of the CBA have also tended to overlook the importance of qualitative benefits

[1] Stephen Littlechild *Comment on two items arising from the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review* 2019, para 17.
[2] NERA *Review of Electricity Authority's transmission pricing review 2019 papers* 2019, para 15.
[3] NERA *2019 transmission pricing review – review of certain economic reports* 2019, para 2.

identified by the Authority. We reiterate that good regulatory practice confirms that the Authority has appropriately been guided by the substantial unquantified benefits of its preferred proposal.

Several submitters allege that the Authority's proposal is contrary to the Government's climate change objectives. This allegation is unfounded. The suggestion that thermal generation will increase because of TPM reform is overly simplistic, ignores the role of hydro generation to meet peak demand, fails to recognise other climate policy tools, and ignores the fact that an efficient electricity system is the best way to reduce emissions. Modelling by various parties, including the Interim Climate Change Committee, indicates that irrespective of TPM reform some new gas peaking generation will be built in the medium term alongside a significant amount of renewable generation and the retirement of baseload thermal generation. This results in the New Zealand electricity system achieving around 95 percent renewable generation in the next decade and a half while keeping prices low and enabling the accelerated electrification and decarbonisation of transport and industrial process heat. A TPM that enables efficient investment in the grid and in generation and load is entirely consistent with the Government's proposed 2050 targets[4] and with the recently introduced changes to the New Zealand emissions trading scheme.[5]

Some submitters have raised questions about the adequacy of the Authority's process. However, Meridian considers the Authority's process is robust. It has correctly understood and elaborated upon its statutory objective. It has consulted and re-consulted on all key aspects of the current TPM proposal. It has heard submitters' views and continues to listen to them including in this round of cross-submissions. As a result, the Authority's proposal appropriately guides Transpower in its implementation of a new TPM.

None of the submissions have altered Meridian's view that without urgent reform, New Zealand faces the prospect of ongoing inefficient grid use, significant inefficient investments and a development path that costs consumers more than it should. We endorse the expert views of Stephen Littlechild, a former electricity sector regulator, who says that it is now time for the Authority to advance TPM reform without further delay.[6]

Meridian remains a strong supporter of the Authority's proposal and looks forward to the publication of the final TPM Guidelines and to the next stage of TPM development.

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[4] Climate Change Response (Zero Carbon) Amendment Bill.
[5] Climate Change Response (Emissions Trading Reform) Amendment Bill.
[6] Stephen Littlechild *Comment on two items arising from the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review* 2019, para 25.

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Part B: The HVDC charge

The Authority has consistently identified the problems with the HVDC charge. In general, submitters accept that there is a problem with the HVDC charge, including submitters that have otherwise been opposed to or reticent about aspects of the Authority's TPM proposals such as Transpower and Trustpower. The Lantau Group (advisors to the TPM Group of industry participants who have raised concerns about the Authority's proposal for TPM reform) recognise that the HVDC charge is not defensible:[7]

> "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."

While there is broad agreement about problems with the HVDC charge there is more diversity in the suggestions about how the HVDC should be treated under a new TPM:

- some submitters advocate for a bespoke HVDC charge to North Island and South Island generators;[8]
- others seek the recovery of the HVDC investments via a residual charge on load;[9]
- Mercury seeks a residual charge that locks in the current interconnection and HVDC charges;[10] and
- others like Meridian agree with the Authority's proposal to include the HVDC in the benefit-based charge.

Aside from the Mercury submission, there is general agreement that South Island generators should not be the sole payers of the HVDC charge. The varying views are split according to participant type with network companies tending to favour options whereby generators pay for the HVDC, and generators tending to favour options whereby load pays for the HVDC.[11] Views seem to align with the anticipated impact of the benefit-based charge and whether or not an individual submitter stands to pay more or less as a result.

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[7] The Lantau Group *Review of Transmission Pricing Guidelines Issues Paper* 2019, p 22.
[8] For example Transpower submission, p 12; The Lantau Group, p 8; The Distribution Group submission, p 4; Northpower submission, p 14.
[9] For example Trustpower submission, para 1.1.58; Pioneer submission, p 4 (although Pioneer also recommend a 50/50 split for generation and load on a net $/MWh basis).
[10] Mercury submission, p 6.
[11] Or in Mercury's case an option whereby generators other than Mercury pay for the HVDC. Mercury is the only major generator that has an exclusively North Island asset base and under the current TPM does not pay any of the cost of the interconnected grid.

Although the Authority should consider the alternative proposals for charging for the HVDC link, there is nothing in the submissions to demonstrate that any alternative is economically superior to, or more advantageous from a fairness or durability perspective than the Authority's proposal to include the HVDC assets in the benefit-based charge. As Professor Littlechild has said, in situations such as these it is appropriate for the Authority to now implement its proposed policy, having come to a view about the best way to address the concerns about the current TPM.[12]

The HVDC is one of the existing transmission assets proposed for inclusion in the benefit-based charge. Views on the HVDC are distinguishable from submissions on the inclusion of existing assets in the benefit-based charge more generally – those submissions are addressed below in Part C.

[12] Stephen Littlechild *Comment on two items arising from the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review* 2019, para 25.

Part C: The benefit-based charge

There is broad agreement by most submitters about the idea of a benefit-based charge which recovers the cost of investments from those who benefit from them. Many submitters including Meridian also support the Authority's proposal to apply the benefit-based charge to existing assets as well as to new investments. Not all are in favour of applying the benefit-based charge to existing assets generally or to the seven assets identified in Schedule 1. However, the objections that have been made to that effect are not sound.

Inclusion of existing assets

The Authority has identified seven existing transmission assets to which the benefit-based charge will apply and also identified the beneficiaries of those assets in Schedule 1 of the proposed Guidelines.

Several submitters,[13] largely from the upper North Island, oppose the application of the benefit-based charge to existing assets (although, as noted above, some of those submitters accept the case for reform of cost allocation for the existing HVDC assets).[14] On the other hand some distributors,[15] generator-retailers,[16] and large industrial consumers[17] support the application of the benefit-based charge to existing assets and many argue that the benefit-based charge should apply to as many existing assets as possible, not just the seven identified by the Authority.

Those opposed to the inclusion of existing assets in the benefit-based charge suggest that:

- the identification of the seven assets is arbitrary;
- changes to cost allocation for existing assets represent a regulatory risk that could undermine investor confidence; and
- inclusion of existing assets results in no quantified benefits.

Meridian disagrees with all of these arguments.

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[13] For example Vector submission, p 4, 8 and 9; Northpower submission p 22 and 23; the TPM Group submission, p 5; Mercury submission, p 2; NZ Steel submission p 2 and 17; and Refining NZ submission, p 2 and 5.
[14] For example The Lantau Group, p 5.
[15] For example EA Networks submission, p 2; and Unison and Centralines submission, p 2.
[16] For example Nova submission, Q14 and Q15.
[17] For example Rio Tinto submission, p 7.

The Authority did not arbitrarily identify existing assets and in fact developed the proposal based on the following criteria – post-2004 investments, with value in excess of $50 million, and with quantified net private benefits in excess of the cost of investment.[18] The result is a short list of existing assets where data is available to enable the quantification of benefits and the costs of implementation are reduced while still capturing a large part of the total value of pre-2019 investments and the benefits of applying the benefit-based charge to those assets. The proposal also avoids benefit-based charges for existing assets where charges would be in excess of the net private benefits quantified by the Authority.

There are real benefits to including existing assets in the benefit-based charge. The Authority's cost-benefit analysis did not quantify all of these benefits. However, this does not mean there are no benefits, rather it reflects the difficulty involved in quantifying durability and other benefits as part of any allocation exercise. Including existing assets will improve signals for efficient load and generation decisions, which will be a significant improvement on the status quo.

A key contention put forward by opponents is that changes to cost allocation for existing assets represent a regulatory risk (that is, the breach of a regulatory compact) that could undermine investor confidence. Other submitters like EA Networks, Unison and Centralines strongly disagree and take the position that perpetuation of the status quo undermines durability. For example:[19]

> "Stakeholders that are in regions that have benefitted from transmission investments and therefore benefit from these implicit subsidies, will no doubt argue that it is unfair to implement changes in allocation methodologies after investments have been made. Or they may argue that there are too many flaws or too many assumptions in the models used to come up with benefits-based allocations such that they should not be used.
> … stakeholders in those regions should not be surprised that a regulator would subsequently make changes to allocations where the status quo results in material inequitable outcomes. This is particularly the case when those inequitable outcomes are in the form of subsidised investments that benefit those stakeholders at the expense of stakeholders who derive no benefit from those investments. Confidence and certainty in regulation is enhanced when a regulator acts to address an objectively unreasonable outcome."

[18] The exception for Pole 2 of the HVDC is reasonable given the way the HVDC functions and the difficulties of separately identifying the benefits of a single Pole.
[19] Unison and Centralines submission, p 2.

Nova too has pointed out that parties benefitting from existing investments have partially had a free ride to date and that it would not be justifiable to extend a subsidy into the new pricing regime through the perpetual spreading of costs rather than use of the benefit-based charge.[20]

Meridian asked Professor Stephen Littlechild to consider the application of the benefit-based charge to existing assets in the report attached to this cross-submission. Professor Littlechild argues that:[21]

> "…investors would have expected a regulatory regime to be looking to transform the sector over time and, in particular, to develop transmission pricing and other arrangements to be more consistent with what one would find in the private rather than public sector. Given that the EA is moving towards prices that better reflects costs and benefits, it is hard to see how investors would be less confident in the regulatory regime. On the contrary, investors would see a regulator confidently and competently adapting to a more competitive market, and going through due process and taking all reasonable steps to ensure that it understands the issues and implications for investors as well as customers and other market participants."

In addition to durability benefits, Professor Littlechild's 2016 report highlights the efficiency benefits that result from the inclusion of existing assets in the benefit-based charge. According to Professor Littlechild:[22]

> "…customer responses to charges for past investments can reveal important information to improve the quality of future investment decisions… Incorporating the costs of past transmission investments into transmission charges will send more informative signals for use of the grid and investment by load and generation customers, notably about locational decisions and substitutes for transmission."

Professor Littlechild's 2016 report was cited favourably by the Authority[23] and the same sentiments are reflected in the Rio Tinto submission that "better signals would be sent to

[20] Nova submission, Q14.
[21] Stephen Littlechild *Comment on two items arising from the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review* 2019, para 17.
[22] Stephen Littlechild *Report on the Electricity Authority's Transmission Pricing Methodology Review* 2016, para 4.
[23] See the Electricity Authority *2019 issues paper*, p v and 118.

consumers about the economic cost of using the grid if Transmission charges are set on the basis of beneficiary pays”.[24]

For all the reasons set out above, Meridian agrees with the Authority that the inclusion of seven existing investments in the benefit-based charge is consistent with the Authority’s statutory objective and would result in a more durable and efficient TPM that is to the long-term benefit of New Zealand consumers.

The process to re-open the benefit-based charge for an asset

Meridian submitted that there may be merit in a regular (say five-yearly) review mechanism for the assessment of benefits under a benefit-based charge. Several other submitters agreed with this proposition. Contact recommends transmission charges be recalculated and reallocated at each regulatory control period,[25] Nova too suggests a rolling reset every four to five years,[26] and Powerco proposes a periodic update of benefit shares to align with Commerce Commission changes to transmission cost during the reset for each regulatory control period.[27]

Meridian therefore continues to see benefits in a more mechanistic review process including:

- maintaining closer alignment of benefits and charges in situations where the substantial and sustained change in grid use threshold has not been triggered;
- reducing the number of times that Transpower must carry out assessments for a substantial and sustained change in grid use (and face lobbying to do so); and
- reducing the degree of contention during Transpower’s initial assessment of beneficiaries.

[24] Rio Tinto submission, p 7.
[25] Contact submission, p 4.
[26] Nova submission p 1.
[27] Powerco submission p 2.

Part D: The Authority's cost-benefit analysis

Opponents of TPM reform have asserted errors in the Authority's cost-benefit analysis (CBA). Meridian asked NERA to review the criticisms of the CBA contained in the expert reports submitted in this round of consultation. The attached NERA report makes it clear that the Authority's CBA withstands scrutiny. NERA's analysis demonstrates that there is reason to doubt the validity of many of the criticisms of the CBA. NERA also calculates that even assuming the criticisms are made out (which we do not think is the case), when they are properly accounted for the CBA nevertheless still indicates a significant quantified net benefit.

Economic criticism of the CBA has focused on the effect on price in the wholesale electricity market under the Authority's proposal. Although the expert reports do not appear to dispute the existence of that effect under the Authority's proposal, some submitters take issue with the modelling of that effect, alleging among other things a failure to count $1.94b of generation investment as a cost of the CBA. Opponents have argued that most of the consumer surplus gains calculated as part of the energy price effect are transfers, not efficiency gains. NERA has reviewed these arguments and it concludes that these submitters "measure the wrong thing".[28] NERA explains possible reasons for these submitters' calculation errors, but the end result is that the transfer aspect of the energy price effect has been overstated in submissions and reports critiquing the CBA.

There is also no merit in the submissions that suggest there is no need to urgently implement TPM reform because the net benefits are not modelled to take effect until several years in the future. It is wrong as a matter of principle to delay much-needed reform merely because net benefits will not occur for some time. That is particularly important in light of the Authority's statutory objective in section 15 of the Act, which tasks the Authority with considering the *long-term* benefit to consumers. Furthermore, delay to TPM reform does not make sense because once reform is implemented, it would take several years for the dynamics to result in material net benefits – delaying the reform would simply delay the realisation of such benefits further.

NERA has also identified oversights and inconsistencies in the critiques and calculations of other submitters. NERA concludes that, even leaving aside the energy price effect, a proper

[28] NERA *2019 transmission pricing review – review of certain economic reports* 2019, para 12.

accounting of all the costs and benefits gives a quantified net benefit of $279.3m, on the most conservative assessment.[29] That is, even assuming the criticisms of the energy price effect part of the CBA are correct for the sake of argument, the Authority's proposal nevertheless has a positive quantified net benefit. NERA also estimates the magnitude of the benefit from the energy price effect as being in the order of $225m per year, or $3.1b in present value terms.[30]

The criticisms of the CBA by submitters have also tended to overlook the importance of the qualitative benefits identified by the Authority. We reiterate our submission that good regulatory practice confirms that the Authority has appropriately been guided by the significant unquantified benefits of its proposal in preferring a durable option over an alternative without those benefits.

Meridian therefore remains of the opinion that even under the most conservative assumptions the Authority's proposal will deliver significant benefits to New Zealand consumers.

[29] NERA *2019 transmission pricing review – review of certain economic reports* 2019, para 26-31.
[30] Ibid, para 21.

Part E: Consistency with climate change objectives

Some submitters argue that removing the RCPD charge will lead to an increase in peak electricity demand and therefore that more thermal generation will be required to meet peak demand.[31] Those submitters assert that the TPM proposal is therefore inconsistent with the Government's climate change objectives. Meridian disagrees as do other submitters like Great South, Invercargill City Council, Southland District Council, Gore District Council and Environment Southland, who say the opposite – that retaining the current TPM would be contrary to emission reduction targets:[32]

> "The current practice of charging South Island generators for meeting the costs of the Cook Strait cable is supressing investment in new South Island renewable electricity generation, locking New Zealand into a future of meeting reserve generation with North Island fossil-fuelled generation. This method of transmission pricing seems to be out of step with New Zealand's wider commitment to meeting climate-change emission reduction targets. We acknowledge that emissions reduction is currently beyond the Electricity Authority's mandate, but an efficient electricity network and transmission system will be a significant enabler of decarbonising our economy."

Meridian agrees with the submission above and considers TPM reform to be an enabler of New Zealand's contribution to the global effort under the Paris Agreement to limit temperature increase to 1.5° Celsius. Without TPM reform, New Zealand faces the prospect of ongoing inefficient grid use, significant inefficient investments and a development path that costs consumers more than it should and therefore disincentivises the electrification of transport and industrial process heat.

It is also wrong to say that as a result of the TPM proposal, New Zealand would need more gas peakers and would have less renewable generation. Modelling undertaken by Meridian, the Interim Climate Change Committee (ICCC),[33] the Productivity Commission[34] and

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31 For example Transpower submission, p 4; Northpower submission, p 2; Pioneer submission, p 2; Oji Fibre Solutions submission, p 2; and Refining NZ submission, p 3.

32 Great South, Invercargill City Council, Southland District Council, Gore District Council and Environment Southland submission, p 2.

33 Available at https://www.iccc.mfe.govt.nz/assets/PDF_Library/daed426432/FINAL-ICCC-Electricity-report.pdf

34 Available at https://www.productivity.govt.nz/assets/Documents/4e01d69a83/Productivity-Commission_Low-emissions-economy_Final-Report.pdf

others[35] consistently indicates that baseload thermal plant will exit the market over the next decade and a half and that there will be significant investment in new renewables supported by investment in gas peaking generation. Peak demand in the medium-term is managed in these models through a combination of gas peaking, demand response, and more flexible use of hydro generation. We would not expect the TPM to alter the mix of future generation investments.

The construction and use of gas peakers is consistent with a future in which the New Zealand electricity market achieves around 95 percent renewable generation over the next fifteen years while keeping prices low to support the accelerated electrification of transport and process heat. This is the smartest way New Zealand can actively and significantly reduce emissions and improve the competitiveness of New Zealand business in a global context. The ICCC's modelling shows the accelerated electrification of transport and process heat can deliver significant net emissions reductions (5.4 million tonnes carbon dioxide equivalent per year by 2035) and more than triple the emissions reductions compared to pursuing a 100 percent renewable electricity goal in that timeframe.

The Government has a range of other policy tools available to drive emissions reduction, most importantly the Zero Carbon Bill recently reported back from Select Committee[36] and the changes to the New Zealand Emission Trading Scheme (ETS) in a bill recently introduced to Parliament.[37] The removal of the $25 fixed price option for ETS emissions units, alignment of ETS unit volumes to be auctioned with emissions reduction targets, and the controlled phasedown of free industrial allocations will ensure least-cost emissions reductions across the whole economy. The TPM proposal is entirely consistent with and will support these wider reforms.

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35 For example Transpower's *Te Mauri Hiko* available at: https://www.transpower.co.nz/sites/default/files/publications/resources/TP%20Energy%20Futures%20-%20Te%20Mauri%20Hiko%2011%20June%2718.pdf

36 Climate Change Response (Zero Carbon) Amendment Bill.

37 Climate Change Response (Emissions Trading Reform) Amendment Bill.

Part F: Process for the development of the TPM

Meridian supports the Authority's process to date and, subject to the comments on process in our submission, also supports the Authority's proposed process for the remaining steps for the development of the TPM.

Process to date

Meridian supports the Authority's process to date. Several submitters have expressly acknowledged that the Authority's process to date has been appropriate.

Nevertheless, some submitters have suggested that the Authority's process in this round of consultation has been defectively short[38] or is an abrupt reversal of an earlier position without explanation.[39] We disagree. As to timing, the Authority notified all interested persons of the scheduled release date well in advance, giving parties several months of lead in time to begin preparatory work. It has given sufficient time in the ten weeks afforded for submissions to be prepared, and in the subsequent four weeks afforded to cross-submissions. The Authority's proposal has built on the substantial work to date, on which parties have previously submitted and the details of which they will be well aware of.

As to changes in the Authority's thinking over the years, the Authority has provided comprehensive information about changes to its TPM proposal over time. The changes it has made reflect the feedback it has received from submitters. It has consulted widely with interested parties, and has re-consulted a number of times on key aspects as well as on entire proposals over the last nine years. Key subjects of targeted consultation include problem definition, decision-making and economic framework, the connection charge, and the beneficiaries-pays concept of transmission charging. Other key features of the current proposal have been consulted on as part of the Authority's proposals including in 2012, 2015 and 2016. That includes elaboration of the Authority's decision-making and economic framework, the application of a new TPM to existing assets, the nature and incidence of the residual charge, and the prudent discount policy. We consider the Authority's current proposal for TPM Guidelines has been amply signalled and represents an evolution of the Authority's thinking over the years.

[38] For example NZ Steel submission, p 19-20.
[39] For example Axiom *Economic review of transmission pricing review consultation paper: A report for Transpower* 2019, p vii.

Some submitters have suggested the Authority has misinterpreted its statutory objective, and they say the Authority is not obliged or meant to pursue sector-wide economic efficiency.[40] In our view the Authority has understood its statutory objective correctly and has used the principles it has elaborated upon appropriately as tools to identify various options. More importantly, the Authority's proposal is consistent with its statutory objective, which must be the ultimate test. The proposal meets the statutory objective in section 15 as it will correct the efficiency and durability problems with the status quo, and will bring substantial quantified and qualitative benefits that are well in excess of the associated costs.

Remaining steps

The Authority's draft Guidelines should now be finalised. We have made suggestions for improving the wording of the draft Guidelines in our earlier submission. We disagree with the assertion that the Guidelines are too prescriptive to be true "guidelines" and so may not be lawful.[41] The draft Guidelines perform the function of guiding Transpower in developing a new TPM. They appropriately contain a description of the purpose and function of each of the main components of the TPM. They direct Transpower to develop detailed mechanisms, for example simple and standard methods for calculating charges. Although they are prescriptive in parts, that does not alter the role that will obviously be played by the Guidelines, when Transpower develops the draft TPM.

Transpower has submitted that it requires no fewer than 18, and preferably 24 months to develop a draft TPM, as it wishes to engage closely with stakeholders. Transpower views "constructive and highly engaged stakeholder participation" as "key to achieving a successful development and implementation of any new TPM."[42] We disagree about the utility of Transpower's intended approach to implementing the TPM. The Authority's proposal is well understood, and submitters' positions are already clear. Transpower's intended approach will simply invite further objection from those parties who would benefit from delay in TPM reform, without improving the quality of the information available to Transpower or improving its ability to understand participants' views.

Transpower can and should confidently develop a TPM without further comprehensive engagement with stakeholders, safe in the knowledge that its checkpoints with the Authority along the way, and the Authority's subsequent review and approval of the TPM, will provide

[40] For example Trustpower submission, p iii and v.
[41] Trustpower submission, para 1.1.62.
[42] Transpower submission, p 10.

the necessary transparency, stakeholder engagement, and quality assurance for the new TPM. We consider that a direction to that effect from the Authority would be useful.

Meridian also notes the significant financial implications of delay for the country's largest electricity consumer. Rio Tinto has recently announced to the market that it will conduct a strategic review of its interest in New Zealand's Aluminium Smelter at Tiwai Point, to determine the operation's ongoing viability. Rio Tinto has said they will consider all options, including curtailment and closure. Transmission charges are a key input cost for the smelter and the Rio Tinto review highlights the urgency of TPM reform for the future of the smelter and those employed by it in Southland. The Authority should consider the scope of the prudent discount policy in the Guidelines, including for situations of inefficient exit by transmission customers or where transmission charges exceed the standalone costs of delivering electricity to a customer. However, the best thing the Authority can do now is progress the TPM proposal without further delay. Anything less will not only jeopardise the future of the smelter but also perpetuate ongoing inefficient grid use, inefficient investment and a development path that costs consumers more than it should.

As former UK electricity regulator Professor Littlechild has opined, "it is now time to implement the proposed policy".[43]

[43] Stephen Littlechild *Comment on two items arising from the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review* 2019, para 25.

Part G: Attachments

NERA Report

Stephen Littlechild Report

NERA
ECONOMIC CONSULTING

2019 transmission pricing review – review of certain economic reports

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31 October 2019

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1. Introduction and executive summary

1. We have been asked by Meridian Energy to review the following four reports filed with the Electricity Authority in response to the Authority's issues paper (**"IP"**) and accompanying technical paper (**"TP"**)[1] describing proposed reform to the transmission pricing methodology (**"TPM"**):

   a. Axiom Economics ("Economic review of transmission pricing review consultation paper") for Transpower, dated September 2019;

   b. HoustonKemp ("Review of the cost benefit and options analysis of the EA's proposed TPM guidelines") for Trustpower, dated 30 September 2019;

   c. Professor Derek Bunn ("A Commentary on the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review") for Vector, dated 25 September 2019; and

   d. The Lantau Group ("Review of Transmission Pricing Guidelines Issues Paper 2019") for the TPM Group, dated 1 October 2019.

2. A summary of our views is as follows:

   a. None of the four reports disputes the Authority's proposition that TPM reform would affect the energy market as well as the grid market. Rather, the primary critiques (particularly by the Axiom and HoustonKemp reports) relate to the *CBA modelling* of the energy price effect, not its *existence*.

   b. In our view, the effect of TPM reform on the energy market would be positive, with the only question being how material. This is because if we remove what these expert reports agree are distortionary grid prices (the RCPD and SIMI),[2] the demand-side of the energy market would purchase energy from the cheapest suppliers, something that would not occur under the existing TPM scenario.

   c. We agree there are some issues with the Authority's modelling of this energy price effect. In an attempt to provide some feel for how large the energy price effect might be, we undertake a high-level analysis, which suggests the energy price effect would create a large positive benefit.

   d. Even if we set aside the energy price effect, the CBA would still be positive, with net benefits occurring from 2027 onwards (versus 2034 if the Authority's existing energy price effect modelling is included).

   e. International evidence and economic theory support the residual being allocated to load.

   f. There are efficiency and fairness reasons for including existing assets under the proposed regime. Even if they suggest different methods for achieving it, the Bunn and Lantau Group reports acknowledge the efficiency and fairness concerns with the way in which the HVDC link in particular is currently funded, and support its reform.[3]

[1] And some further accompanying papers.

[2] Note that the Lantau Group report does advocate continuing with the RCPD, but at a much lower level.

[3] Neither the Axiom nor HoustonKemp reports appears to suggest how the HVDC costs should be recovered.

2. Critiques of energy price effect modelling

2.1. Introduction

3. As we described in section 5.2.1.1 of our 1 October 2019 report, the Authority analysed two effects under its "more efficient grid use" modelling:

   a. What we termed a "grid price effect", being the improvement in allocative efficiency of grid use; and

   b. An "energy price effect", being the improvement in efficiency of the wholesale electricity market.

4. The Axiom and HoustonKemp reports argue there are some fundamental flaws with the Authority's CBA, particularly the energy price effect component:

   a. The Authority's modelling predicts that generators would invest $1.94b (present value) in new plant despite wholesale revenues falling by $3.655b (present value);

   b. That $1.94b of generation investment is not counted as a cost; and

   c. The bulk of the consumer surplus gain is a transfer, not an efficiency gain.

5. We note these critiques relate to the *modelling* of the energy price effect, not the *existence* of the energy price effect – none of the four reports disputes the Authority's proposition that TPM reform would affect the energy market as well as the grid market.

6. We discuss these three critiques below (section 2.2). We also set out an alternative approximation of the energy price effect (section 2.3).

2.2. Assessment of the critiques

2.2.1. Investment decision rule

7. The Axiom and HoustonKemp reports are critical of the Authority's modelling that predicts generators would invest $1.94b (present value) in new plant despite wholesale revenues falling by $3.655b (present value). They identify that this outcome is driven by the investment decision rules used by the Authority's modelling, particularly that:[4]

   a. Each generator is assumed to dispatch every MW it offers, regardless of demand; and

   b. Investment will occur if wholesale prices exceed LRMC in the year plant is built.

8. We think these critiques warrant a response – the investment decision rules do appear to be simplistic, leading to what appear to be odd outcomes. It would be preferable to use more sophisticated investment decision-making rules.

2.2.2. Treatment of generation investment cost

9. The HoustonKemp and Axiom reports also make the argument that the $1.94b in generation investment should be treated as a cost under the CBA. We also raised this issue at [81-82] of our 1 October 2019 report, pointing out that it would be useful for the Authority to explain why it treated these costs dissimilarly to saved battery costs and increased grid costs.

10. Regardless, if the investment decision-making rules in the model are flawed, the results of those decision rules (being the $1.94b, but also the resulting energy price effect benefits) should not be included in the CBA.

[4] See page 87 of the Axiom report and page 56 of the HoustonKemp report.

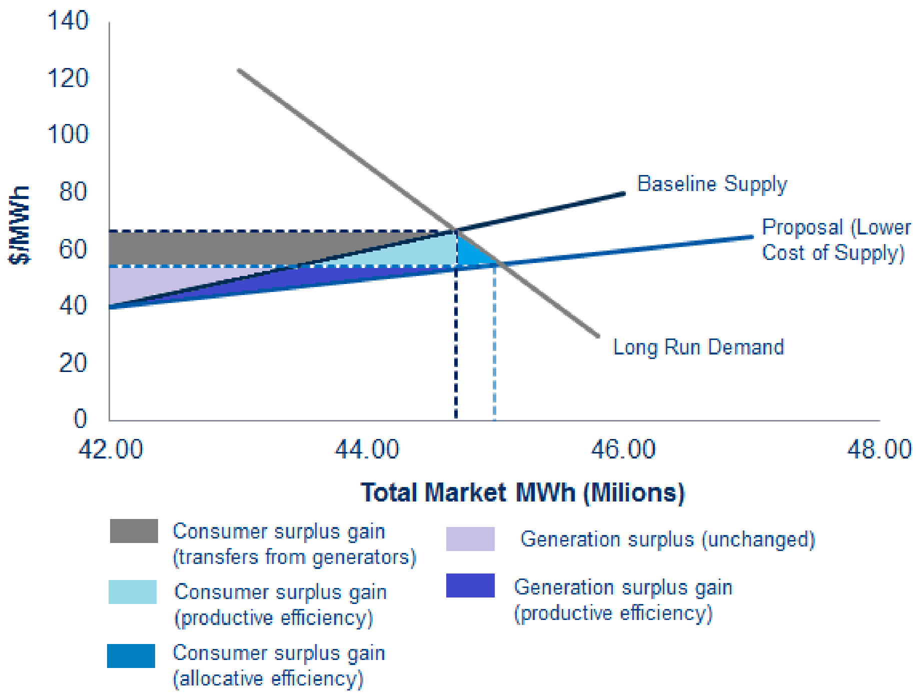
2.2.3. Transfers

11. Both the Axiom and HoustonKemp reports argue the vast majority of the consumer surplus gains calculated by the Authority (as part of the energy price effect) are transfers rather than efficiency gains. Interestingly the two reports get quite different estimates of the transfer component: $1.9b out of $2.6b for Axiom and $4.319b out of $4.37b for HoustonKemp.[5]

12. Regardless, both reports measure the wrong thing.

13. This can be seen most clearly by comparing Figure 4.2 of the HoustonKemp report with Figure 2 of our 1 October 2019 report (for ease of reference, set out again as Figure 1 in this report), which is a replication of the right-hand panel of slide 14 presented by the Authority at its 10 September 2019 workshop. The HoustonKemp report has wrongly included the triangle shaded light blue (labelled "consumer surplus gain (productive efficiency)") in our Figure 2 (Figure 1 of this report) as a transfer, when it is in fact new surplus, i.e., an efficiency.[6] This error may arise because the HoustonKemp report does not include a shifting supply curve in its Figure 4.2.

Figure 1: Long run energy price effect



14. The Axiom report does include a shifting supply curve (see, e.g., Figure ES.8), but still omits to exclude from the transfer calculation the part of the darkly shaded rectangle that falls below the original supply curve, S_0. This triangle is the equivalent to the light blue shaded triangle in our

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[5] See page 90 of the Axiom report and page 45 of the HoustonKemp report.

[6] To see this (using Figure 1of this report), compare the total surplus under the baseline scenario (i.e., the area between the demand curve and the baseline supply curve) to the total surplus under the proposal scenario (i.e., the area between the demand curve and the proposal supply curve). The extra area, made up of the purple, light blue and darker blue triangles, is the overall efficiency gain.

Figure 2 (Figure 1of this report) and represents a consumer surplus gain that is not a transfer from producer surplus.

15. We are not disputing that the Authority's energy price effect includes transfers and that these might be large. Our points are that:

    a. The Axiom and HoustonKemp reports' calculations overstate these transfers as they include an area under the initial supply curve in the wealth transfer calculations, when it is really a new benefit. Our calculations (which we expand on in section 2.3) suggest that the area in these wealth transfer calculations that is below the initial supply curve could represent from 6% up to 50% of the area calculated as wealth transfers (depending on the slope of the supply curves); and

    b. The Authority expressly recognized that the energy price effect would include transfers, and accounted for the difficulty in delineating these by averaging the energy price effect and the grid price effect.

16. As an aside, neither the Axiom nor HoustonKemp reports include efficiency gains arising for generators, being the dark purple triangle in our Figure 2 (Figure 1of this report). Like the other triangles making up the new surplus, these gains reflect the use of cheaper generation under the reform scenario compared to the baseline scenario, and represent a gain for society. Our calculations in the next section include these.

2.3. The energy price effect must be positive

17. As noted, none of the four reports we have reviewed disputes the Authority's proposition that TPM reform would affect the energy market as well as the grid market. Furthermore, even if it is difficult to quantify, the energy price effect must be positive. This is because if we remove what the expert reports agree are distortionary grid prices (the RCPD and SIMI),[7] the demand-side of the energy market would purchase energy from the cheapest suppliers, something that would not occur under the existing TPM scenario. Or in other words, the market would become more competitive (an outcome the Authority is obliged to promote by section 15 of the Electricity Industry Act 2010).[8]

18. Indeed, this is the concept that appears to underlie the Authority's attempt at modelling the energy price effect, as illustrated by the figure in the right-hand panel of the Authority's slide 14, replicated above in Figure 1of our report.

19. To get a feel for the potential magnitude of the efficiency gains (as opposed to the transfers) from the energy price effect (being the sum of the light blue, dark blue and dark purple triangles in Figure 1), we have undertaken the following analysis.

20. We have calibrated Figure 1 using price and quantity data from the Authority's modelling, as described in Table 1.

[7] Note that the Lantau Group report does advocate continuing with the RCPD, but at a much lower level.

[8] "The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers."

Table 1: Parameters for energy price effect calculation

Parameter	Value	Source
Intercept of demand and baseline supply curves	\$89.54/MWh 44.8 million MWh	Average price and quantity in baseline scenario modelling over 2019 to 2049[9]
Intercept of demand and proposal supply curves	\$79.52/MWh 45 million MWh	Average price and quantity in reform scenario modelling over 2019 to 2049[10]
Intercept of supply curves with price axis	\$79.52, \$70, \$60 and \$10	Maximum possible supply curve intercept (flat supply curve)[11] and assumed lower intercepts (declining supply curves)

21. Based on this calibration, we calculate the sum of the light blue, dark blue and dark purple triangles to be approximately \$225m per year, or \$3.1b in present value terms.[12]

22. We emphasise this is a very approximate calculation and is clearly dependent on assumptions about price and quantity under the factual versus counterfactual, as well as the position and shape of the demand and supply curves. However, it does serve to suggest that the potential efficiency gains in the energy market do exist and are material.

2.4. NERA cross-check

23. In section 5.2.1.2 of our 1 October 2019 report, we carried out a simple calculation to illustrate that the Authority's CBA result of \$2.6b (present value) was plausible, in light of:

    a. Empirical studies finding allocative efficiency effects of between 1% and 27% of market revenue; and

    b. The \$2.6b (present value) being 1.6% of the present value of the sum of Transpower's expected revenue and expected wholesale electricity market revenue over the next 30 years (\$160.6b, present value).

24. For the wholesale electricity market revenue input to that calculation, we used the latest estimate from the International Energy Agency 2017 New Zealand Review that groups the revenue of the

[9] Rcpd file from https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper/2019_Cost_Benefit_Analysis%20(including%20additional%20files)/Grid%20use%20model/Output/All_major_capex/rcpd.csv

[10] Aob file from https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper/2019_Cost_Benefit_Analysis%20(including%20additional%20files)/Grid%20use%20model/Output/All_major_capex/aob.csv

[11] A flat supply curve is of course not realistic – we just use this to illustrate one extreme. As we set out in the next footnote, the results are actually not that sensitive to the vertical intercept of the supply curves.

[12] The area of these triangles changes slightly with different assumptions for the supply curve intercept:

Intercept	Area	PV of area
\$79.52	\$225.48m	\$3,103.72m
\$70	\$225.93m	\$3,109,87m
\$60	\$226.72m	\$3,120.78m
\$10	\$231.31m	\$3,183.95m

five largest generators (NZ$10,116m), and assumed the amount would remain constant during the next 30 years.[13]

25. We note how much larger this figure is than that referred to on page 44 of the HoustonKemp report, which is $4.2b. If we instead use this number for expected wholesale electricity market revenue for each of the 30 years, then the Authority's CBA result of $2.6b (present value) as a proportion of the present value of the sum of Transpower's expected revenue and expected wholesale electricity market revenue over the next 30 years would be 3.52%.

[13] See footnote 25 of our 1 October 2019 report. The NZ$10,116m comes from Table 5.1, which also lists generation capacity and is under the heading, "Wholesale market".

3. CBA without energy price effect

3.1. Revised CBA results

26. In this section of our report we set aside the energy price effect and consider the remainder of the Authority's CBA. Setting aside the energy price effect will affect both the benefit and the cost sides of the CBA – we set out the resulting quantification in Table 2 below, noting where a number has changed from the Authority's original result and where we discuss that change in this report.

27. Note in particular that if we leave aside the energy price effect, we need to explicitly add in the benefit of eliminating the SIMI. As we discussed at section 5.2.3 of our 1 October 2019 report, the Authority picked up the undistorted North Island/South Island generation investment decisions (under the reform proposal) in the generation investment forecasts that underlie the energy price effect modelling. Accordingly, if we are setting aside the energy price effect, we need to explicitly add the benefits of the eliminated distortions in.

28. During a previous consultation round, Oakley Greenwood calculated this benefit as being $13.7m (NPV), arising from more efficient investment in generation over the 20-year time horizon (so a shorter time horizon than has been used this time around).[14] The approach involved running the MBIE LRMC model of future generation investment with and without the HVDC SIMI charge, and comparing the NPV of the difference in cost of the generation schedules.

29. For the sake of simplicity, we adopt that $13.7m as the benefit for present purposes.

[14] Oakley Greenwood *Cost Benefit Analysis of Transmission Pricing Options* (11 May 2016) at pp 49-51.

Table 2: Revised CBA results (millions)

Quantified benefits	Present value	Comment
More efficient grid use	$50.8	This is the allocative efficiency benefit only (the "grid price effect"). We do not accept all of the Axiom and HoustonKemp critiques (as we discuss in section 2.2 of this report), but for the moment we set aside the energy price effect.[15]
More efficient investment in batteries	$202	Unchanged – see section 3.2.1 of this report.
More efficient investment in generation and large load	$43	Unchanged – see section 3.2.2 of this report.
More efficient grid investment – scrutiny of investment proposals	$38.5	Halved (was $77m) – see section 3.2.3 of this report.
Increased certainty for investors	$26	Unchanged – see section 3.2.4 of this report.
More efficient investment in generation (NI vs SI)	$13.7	In the Authority's model, the benefit of eliminating the SIMI was included in the energy price effect. Accordingly, we need to add this back – this number has been taken from the earlier OGW CBA.
Total quantified benefits	**$374**	
Quantified costs	**Value**	
TPM development / approval	$8	Unchanged.
TPM implementation costs	$9	Unchanged.
TPM operational costs	$9	Unchanged.
Grid investment brought forward	$66.7	Without the energy price effect, the increase in peak demand would be lower, resulting in less required grid investment – this figure comes from cell G7 of the "Summary grid use model".[16]
Distribution investment brought forward	$0	New entry, but zero – see section 3.2.5 below.
Load not locating in regions with recent grid investment	$1	Unchanged.
Efficiency costs of price cap	$1	Unchanged.
Total quantified costs	**$94.7**	
Net (benefits less costs)	**$279.3**	

[15] Note that this figure is very similar to the $51m used in the table on page iii of the HoustonKemp report. However, the figures are conceptually distinct – the $50.8m we use is the grid use effect allocative efficiency gain, whereas the figure the HoustonKemp report uses is the energy price effect allocative efficiency gain.

[16] Cell G7, tab "Summary grid use model" https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper/2019_Cost_Benefit_Analysis%20(including%20additional%20files)/Summary

30. As can be seen, the CBA would still be positive. This should not be surprising. None of the economics reports filed dispute that (the existing) RCPD and SIMI charges are inefficient.[17] Rather, it appears to be generally accepted these charges distort the way the broader electricity market works. In contrast, the reform would raise Transpower's MAR through fixed, benefit-based charges. The result would be:

    a. The MAR would be raised in a less distortionary way (allocative efficiency);

    b. Electricity would be supplied from cheaper sources (see Figure 2 of our 1 October 2019 report, set out again as Figure 1in this report); and

    c. Grid investments would be more efficient.

31. In fact, as we have already discussed (section 2.3), we think the net benefits are likely to be even larger than those set out in Table 2.

32. It is important to reconcile Table 2 with the figures given by the Axiom and HoustonKemp reports. In particular:

    a. On page xxxvii, the Axiom report claims the net benefit would be -$1.5b once just some of the problems with the CBA are addressed; and

    b. On page iii, the HoustonKemp report claims the grid use net benefit would be -$2.303b once the modelling issues are addressed.

33. In both cases, the key drivers of the results are:[18]

    a. Stripping (alleged) transfers out of the benefits; and

    b. Adding generation investment costs ($1.94b) on the cost side.

34. While we disagree with the Axiom and HoustonKemp calculations of the transfers (as we have discussed in section 2.2.3), we have in effect stripped these out in Table 2 by setting aside the energy price effect.

35. However, on the logic of the arguments made in the Axiom and HoustonKemp reports, the $1.94b should also be excluded from the CBA. As we discussed in section 2.2, both the Axiom and HoustonKemp reports are critical of the generation investment decision rules adopted by the Authority's CBA, and of the implication that generators would spend $1.94b while wholesale revenues are falling by $3.655b. It is these decision rules that generate the $1.94b. It is wrong to argue the CBA decision rules are inappropriate while at the same time including the resulting cost.[19]

36. In our view, the Authority could set aside the entire energy price effect (benefits and costs) as modelled to date. Instead the Authority could rely on the remaining elements of its CBA, complemented by the qualitative analysis that the energy price effect must be positive and our analysis finding that effect is likely to be material.

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[17] Note that the Lantau Group report does advocate continuing with the RCPD, but at a much lower level.

[18] There are other drivers as well in the case of the HoustonKemp report – we discuss these further below.

[19] For the same reason, it is wrong to use the energy price effect allocative efficiency gain as a benefit. Rather, the grid price effect allocative efficiency gain should be used as the benefit. However, these numbers are virtually the same, so make no difference to this analysis.

3.2. Other critiques of the CBA

3.2.1. More efficient investment in distributed energy resources

37. The HoustonKemp report is critical of the Authority's modelling of battery investment, arguing that it is likely to "overstate substantially the extent to which battery investment would be incentivised under the status quo" (HoustonKemp report, page 53).

38. A key aspect of the HoustonKemp argument is that the shaving of demand at peak "means that the marginal benefit associated with each battery declines increasingly steeply with each additional investment" (page 53).

39. We make the following comments:

    a. The HoustonKemp report does not reconcile its argument with the points made by the Authority that ([4.58], IP):

        i. There would be "an upward spiral in the RCPD rate under the status quo, driven by load customers investing in DER (in particular, network-scale batteries) in order to avoid paying the RCPD charge"; and

        ii. "Customers' ability to avoid the RCPD charge in this way is expected to increase over time with the reducing cost of DER (such as batteries)"; and

    b. Even if the HoustonKemp argument was correct, the HoustonKemp report does not provide any evidence that the marginal benefit would decline increasingly "steeply".

40. Furthermore, the HoustonKemp report does not suggest an alternative approach to the modelling, nor does it quantify the effect of its critique. At this stage we continue to use the Authority's number.

3.2.2. More efficient investment in generation and large load

41. One of the rationales for a benefit-based charge is that it would result in grid-connected (or connecting) investors taking into account the impact of their generation and load investment decisions on grid investment costs. This would result in investment decisions being more socially efficient (quantified by the Authority at $43m).

42. Both the Axiom and HoustonKemp reports refer to this role of a benefit-based charge as being a "shadow price". The Axiom and HoustonKemp reports argue that this shadow price would not be accurate or precise and accordingly would be of limited signalling value.

43. It might be the case that when an investor is making a generation or load investment decision, the investor would not have an accurate prediction of future benefit-based charges that might arise. However, the investor would know that any grid investment impact caused by its decision would not be socialised as it is under the status quo TPM – rather, the investor would know that some material cost would be sheeted home to it. Just this change by itself would materially improve the social efficiency of investment decisions.

44. Furthermore, there are also likely to be techniques for forecasting grid investments and benefit-based charges, and it is likely these would improve over time as the demand for them develops.

45. As we noted in our 26 July 2016 report, there can be material efficiency gains by approximate cost allocations to benefits without incurring the transaction costs and risks of attempting to obtain a high degree of precision.

46. Somewhat relatedly, the Axiom report argues the CBA has not modelled the benefit-based charges.[20] We disagree. The CBA models these charges in that it:

   a. Treats them as a fixed cost of recovering Transpower's MAR compared to the variable nature of the RCPD and SIMI; and

   b. Models the impact on load, generation and grid investment, as discussed elsewhere in this report.

3.2.3. More efficient grid investment due to scrutiny of proposed investment

47. The Axiom and HoustonKemp reports are critical of the Authority's quantification of the effect greater scrutiny would have on grid investment. We summarise the arguments made by those reports, and set out our responses, in Table 3.

Table 3: Scrutiny benefit quantification arguments and responses

HoustonKemp and Axiom reports' argument	NERA response
The Authority relies on a single data point.	The Authority may only refer to a single data point, but we provided further evidence in section 5.2.5 of our 1 October 2019 report, pointing out the similarity to the approach taken by the Commerce Commission to productive efficiency quantification in merger authorisation analysis.
A reduction in expenditure may result in lower quality – the avoided cost is not entirely wasteful.	This is a possibility, but the Axiom report provides no evidence for its assertion that (page 103), "The true efficiency gain would be likely to be many magnitudes smaller than 4.4% and, by extension, the percentages that the Authority has adopted are also likely to be overstated substantially".
Stakeholder scrutiny might just replicate the Commission's review process.	A benefit-based charge should improve participation in, and information available to, the Commerce Commission in respect of its decision-making process about proposed grid investments. Therefore we would expect an incremental improvement in decision-making. For example, the Fremeth et al (2014) article cited by the Authority empirically estimates the effect that "public consumer advocates" have on the return on equity of regulated utilities in the US (a 0.45 percentage point reduction in the allowed return on equity).[21]

48. To take account of the first two points discussed in Table 3 above, we conservatively halve the benefit originally calculated by the Authority, i.e., we use $38.5m instead of $77m.

3.2.4. Increased certainty for investors

49. The HoustonKemp report is critical of the Authority's approach to quantifying the benefit of increased certainty, because the assumptions the analysis is based on are "unsupported" (see section 5.2.4). The Axiom report makes similar critiques (section 6.4.3).

50. As we noted in our 1 October 2019 report, the Authority's approach to quantifying this benefit is complicated, albeit under a broadly appropriate (real options) framework. We quantified this

[20] The Bunn report makes a similar point (page 10).

[21] Fremeth, A R, Holburn, G L F and Spiller, P T "The impact of consumer advocates on regulatory policy in the electric utility sector", *Public Choice*, 161(1–2), 2014 pp 157–181.

effect in our 26 July 2016 report using a very conservative, simplified, real options approach. We calculated this benefit to be approximately $50m, i.e., almost double the Authority's number.

51. Therefore we think it is appropriate for the Authority to continue using at least its $26m number.

52. The Axiom report also argues that the real source of uncertainty is the Authority's own review process. However, this ignores that:

    a. The HVDC has been controversial since at least 2008 and perhaps even back to 1996 – see [20] of our 1 October 2019 report; and

    b. It is widely accepted that the RCPD is resulting in costly distortionary, evasive behavior.

3.2.5. Extra distribution costs

53. Both the Axiom and HoustonKemp reports argue the CBA should also include costs of upgrading the distribution networks in order to deal with increased peak demand.

54. The Authority did consider the issue of distribution costs, but decided not to incorporate an analysis of them because (IP, [4.160-4.161]):

    a. The CBA is carried out at the grid exit point level, and does not consider benefits at the end consumer level; and

    b. Of its awareness "that most distribution networks around New Zealand have spare capacity".

55. The Axiom report rejects the first point, arguing the benefits to consumers are already factored into the CBA. However, because the dynamics at the distribution level have not been modelled, we do not think this is correct. In particular, if distribution network investment was required as a consequence of TPM reform, the retail price of electricity would rise to cover those higher costs, in turn reducing peak demand. This dynamic would need to be modelled before any distribution costs could be correctly incorporated as a cost.

56. The Axiom report also rejects the Authority's point about spare capacity. We note that neither the Authority nor the Axiom report point to any empirical evidence about spare capacity, in the absence of which it is not possible for us to form a view. It is possible the Authority has evidence about spare capacity arising from its role as regulator.

57. Furthermore, even if it was appropriate to include the distribution costs, the actual effect would depend on:

    a. How much spare capacity there currently is on distribution networks;

    b. The uptake and location of distributed generation and batteries (including electric vehicles) within distribution networks and the impact of those technologies on peak demand and constraints within distribution networks;

    c. The nature of distribution pricing and extent to which consumers on distribution networks respond to price;

    d. How the estimated increase in peak demand for the grid converts into increased peak demand on distribution networks;[22] and

    e. How much the peak demand increase would reduce if the energy price effect is left aside.

58. Accordingly, without significant further analysis we think there is too much uncertainty to include a number for extra distribution costs in the CBA.

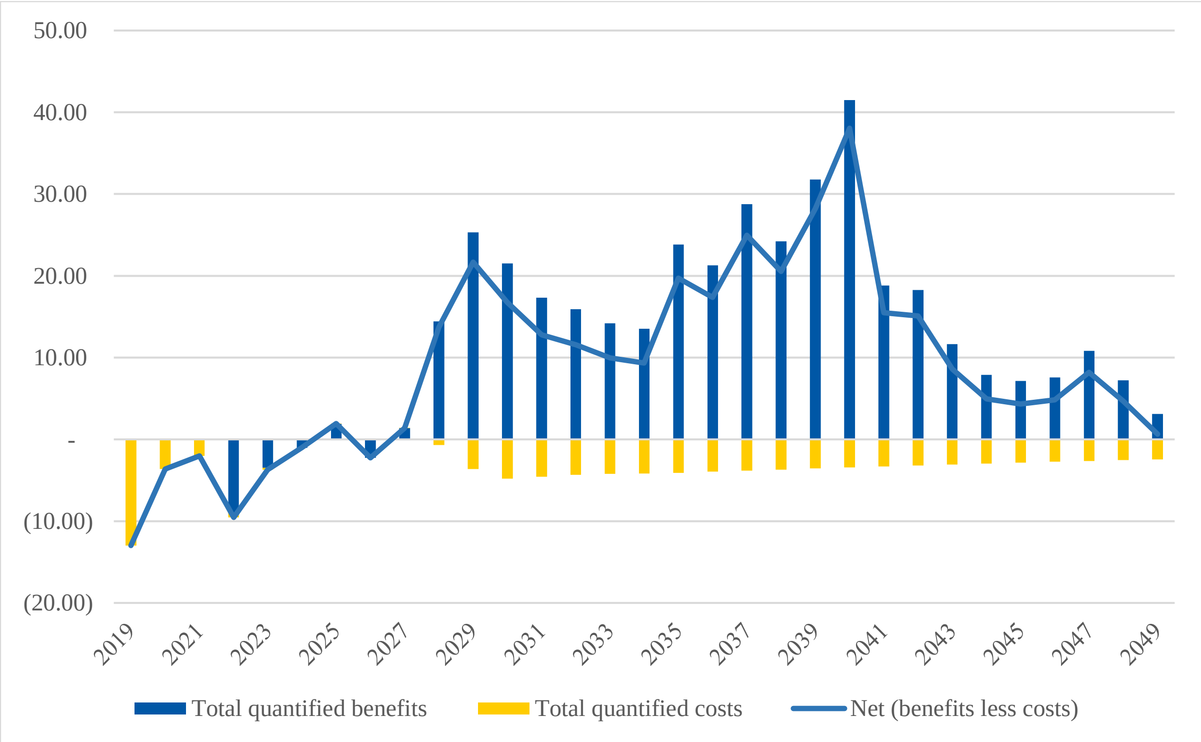
[22] The HoustonKemp report does propose an approach to this (section 4.3.2).

4. CBA time profile

59. The Axiom and HoustonKemp reports point out that the net benefits of the proposed TPM reform do not occur until around 2034, according to the Authority's (energy price effect inclusive) CBA.

60. However, if we leave out the energy price effect (as modelled by the Authority), net benefits would occur earlier, starting in 2028. This is depicted in Figure 2, and the methodology underlying this figure is set out in Appendix A.

Figure 2: Time profile of costs and benefits without energy price effect



61. It is not surprising that it takes some time for net benefits to begin, when there are upfront costs associated with the reform. Indeed, as a matter of principle, just because a reform is not expected to result in benefits for some time does not necessarily mean the reform should be rejected. For example, would we reject a policy of improving pre-school education for at risk children just because the benefits would take a long time to manifest?

62. In this regard, we note that, "The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry ***for the long-term benefit of consumers***."[23]

63. The solution proposed by the HoustonKemp report is to delay implementation of the reform until 2034.[24] But this does not make any sense – assuming the CBA is correct for the moment, what it shows is that once reform is implemented, it would take several years for the dynamics to result in material net benefits – delaying the reform would simply delay that further.

[23] Section 15 of the Electricity Industry Act, emphasis added.

[24] Section 8.3 of the HoustonKemp report.

5. Residual

64. We set out the reasons for our view that the residual should be allocated entirely to load in our 1 October 2019 report. The Bunn report notes that Ofgem has the same view, for two reasons (page 3):

    a. Competitive neutrality between types of generators; and

    b. The charge would ultimately be passed onto load anyway.

65. However, the Bunn report goes on to state it disagrees with the Ofgem view. The Bunn report gives two reasons for this disagreement:

    a. It states that (page 7), "International evidence is mixed on this". However, the evidence set out in Table 2 of our 1 October 2019 report shows that grid charges are overwhelmingly allocated to load across Europe and the US, as well as other countries; and

    b. Because the transmission charges would be fixed, "one would not expect those to go through a simple pass through into the energy market" (page 8). In response, we refer again to what we set out on this point in our 1 October 2019 report, i.e.:

       54. The Authority also points out that if the residual charge was allocated to generation, it would be passed on to load via higher energy prices anyway ([B.224 IP])). Introductory textbook economics might suggest this is only correct to the extent that short-run marginal cost includes the residual charge. However, in a more dynamic sense, fixed costs have to be recovered through the wholesale market – investment in generation will only occur if investors expect to recover their fixed and variable costs, including any fixed transmission costs. If prices are too low to enable recovery of fixed costs, there would be less investment, and ultimately prices would rise.

       55. This is a more general feature of markets – ultimately the demand-side has to pay for all of the costs incurred in producing the goods or services consumed – otherwise no one would invest on the supply-side.

6. Existing investments

66. The HoustonKemp report argues that (page vi), "Changing the allocation of existing investments provides no prospect of promoting more efficient investment incentives and or [sic] achieving more efficient use of the network."

67. We disagree, for the reasons we set out in section 4.2 of our 1 October 2019 report, particularly [15], where we stated there are efficiency reasons to apply the new TPM to existing assets:

    15. In our view, the existing charging regime is clearly inefficient in respect of existing (and future) assets, and therefore it would be inappropriate to leave it untouched. The existing regime leads to dynamically inefficient investment off-grid (generation and load), and deterred use of the grid itself. Therefore there are dynamic, productive and allocative efficiency reasons for altering the regime on existing grid assets. While those assets are sunk, how the costs of them are recovered does alter forward-looking behaviour.

68. While generally supportive of a beneficiaries-pay approach for future assets, the Bunn report also expresses concern about applying that approach to existing assets, and instead recommends these should be recovered by the residual charge. As noted in section 4.2 of our 1 October 2019 report, we agree this would be a valid approach (although as discussed above, we disagree with the Bunn report's arguments regarding allocation of the residual charge – we think the residual should just be charged to load).

69. Finally, it is also noteworthy that both the Bunn and Lantau Group reports[25] acknowledge the efficiency and fairness concerns with the way the HVDC is currently funded, and support reform of it. The Bunn report does not appear to have a specific proposal for the HVDC, although implicitly it might be suggesting recovery via the residual, as noted in the preceding paragraph. The Lantau Group report proposes recovering the HVDC "through a simple $/MWh charge applied to all North and South Island generators" (page 8). We do not agree with this proposal, for the following reasons:

    a. It would continue the arbitrary distinction between the HVDC and other grid investments;

    b. It would recover a fixed cost through a variable charge; and

    c. That variable charge would be passed straight through to load anyway – it would be simpler to recover the HVDC through the residual financed by load, as per the Authority's residual proposal.

70. Neither the Axiom nor HoustonKemp reports appears to suggest how the HVDC costs should be recovered.

[25] See page 2 of the Bunn report and page 3 of the Lantau Group report.

Appendix A. Data series used for the CBA time profile, excluding the energy price effect

The series used for the construction of Figure 2 are detailed below, along with any adjustment made to exclude the energy price effect.

Quantified benefits	Comment
More efficient grid use	We have used the time profile of the gross change in consumer welfare excluding energy price changes, available in the file cs_results of the “all major capex” scenario.
More efficient investment in batteries	We have used the time profile of the change in cost of investment in batteries (proposal less baseline), available in the file total_dg of the “all major capex” scenario.
More efficient investment in generation and large load	We have used the Monte Carlo results available in the investment efficiencies model spreadsheet and spread it evenly across the duration of the CBA.
More efficient grid investment – scrutiny of investment proposals	We have halved the main series used by the Authority for building the time profile of the scrutiny of investment proposals. The series involved are: • In terms of major capex, the time profile of “total major capex” in the tab “Scrutiny – Major capex” of the investment’s efficiencies model spreadsheet. • In terms of base capex, the time profiles of “base capex E&D”, “base capex R&R (3%)” and “base capex R&R (2%)”, in the tab “Scrutiny – Base capex” of the investment’s efficiencies model spreadsheet.
Increased certainty for investors	We have used the Monte Carlo results available in the investment efficiencies model spreadsheet and spread it evenly across the duration of the CBA.
More efficient investment in generation (NI vs SI)	Number taken from the earlier OGW CBA and spread evenly across the duration of the CBA.

Quantified costs	Comment
TPM development / approval	Obtained from cells I39, H70 and G84 in the tab "TPM development cost estimate" of the file Net costs.xlxs, and from cell C6 in the tab "Costs" of the summary of costs and benefits spreadsheet. The costs have been spread according to the duration indicated in the spreadsheets.
TPM implementation costs	Obtained from cells D30 and D61 to F61 in the tab "TPM implementation cost estimate" of the file Net costs.xlxs, and from cell G5 in the tab "Costs" of the summary of cost and benefits spreadsheet. The costs have been spread according to the duration indicated in the spreadsheets.
TPM operational costs	Obtained from cells D45, D65, D85 and P135 in the tab "TPM ongoing cost estimate" of the file costs.xlxs. The costs have been spread according to the duration indicated in the spreadsheets.
Grid investment brought forward	We have used the gross cost less change in LCE ($2018) from the transmission costs spreadsheet of the “demand major capex” scenario.
Distribution investment brought forward	New entry, but zero.
Load not locating in regions with recent grid investment	We have used the Monte Carlo results available in the investment efficiencies model spreadsheet and spread it evenly across the duration of the CBA.
Efficiency costs of price cap	We have used the inputs available at the “net benefit’ tab of the file Efficiency effect of price cap.xlxs and spread it evenly across the first five years of the CBA.

Qualifications, assumptions and limiting conditions

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Comment on two items arising from the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review

Stephen Littlechild[1]

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1. Meridian has asked for my view on two items arising from the 2019 *Issues Paper* released by the Electricity Authority (EA) on 23 July 2019, as part of its Transmission Pricing Review. These items are:

   - Professor Derek Bunn's conclusion (in his Commentary of September 25, submitted by Vector Ltd) that "including 7 legacy investments in the beneficiaries charging is indefensible and undermines confidence in the regulatory regime going forward", and
   - the role of a prudent regulator in a situation where there is broad acknowledgement of problems with the existing transmission pricing arrangements but conflicting views amongst industry participants as to the best solution.

2. My comments will reflect arguments that I set out at greater length in my previous Report of 26 July 2016 to the Review.

Qualifications

3. My qualifications for commenting on this issue are two-fold. First, I was the first GB electricity regulator, as Director General of Electricity Supply and head of the Office of Electricity Regulation (Offer) from 1989-1998. During that period, I dealt with the whole range of regulatory issues in the electricity sector. This included the design of transmission pricing regulation, which covered such matters as are involved in the present EA consultation. Later, I testified on behalf of Offer's successor body Ofgem in a case involving the pricing of transmission losses. This raised a number of similar issues to those with which the EA is presently engaged.

4. Second, both before and after this period as regulator I have been directly concerned as an economist with the nature of competition and the design of regulatory frameworks to best enable the transition from public ownership monopolies to competitive industry structures and practices. My experience has included advising HM Government in 1983 on the regulation of the to-be privatised British Telecommunications via the RPI-X incentive price cap; advising HM Government on the application of the same type of cap to British Gas and the water companies; membership of the Monopolies and Mergers Commission 1983-1989 that included a reference on the pricing policy of British Gas; membership of the Postal Services Commission regulating the soon-to-be privatised Royal Mail; and consultancy engagements around the world, including in New Zealand, advising governments, regulatory bodies and regulated companies on a variety of regulatory issues, typically associated with liberalisation of formerly monopoly markets and the introduction of some form of private ownership.

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The inclusion of seven legacy investments in the beneficiaries charging

5. Professor Bunn accepts that "The direction of change which the EA is proposing is consistent with the consequences of the energy transition, and is not out of step with similar changes elsewhere in the world." But he says that "the apparent anomaly of including 7 legacy investments in the beneficiaries charging is indefensible and undermines confidence in the regulatory regime going forward." (p 10)

6. Consider Professor Bunn's argument in two steps. First, is it appropriate to include legacy investments in a beneficaries charging regime? Second, if so, is it appropriate to exclude certain such investments?

7. Professor Bunn is concerned about the general principle of including legacy investments in a beneficiaries charging regime. He quotes with approval a submission for Trustpower by Professors Bushnell and Wolak which says, "A key feature [of the proposed reforms] is the reallocation of the costs of a subset of existing transmission assets between market participants….they are largely transfers from one set of participants to another that do little, if anything, to improve the economic efficiency of the New Zealand electricity supply industry". (p 7)

8. I explained in my previous report (paras 56-67) why these are not just cost or income transfers between market participants. I said that "customer responses to charges for past investments can reveal important information to improve the quality of future investment decisions." "Incorporating the costs of past transmission investments into transmission charges will send more informative signals for use of the grid and investment by load and generation customers, notably about locational decisions and substitutes for transmission. Applying the new TPM to investments that already exist will enable transmission planners, and load and generation investors and consumers, to make better informed decisions in future." (para 4)

9. The information necessary to make good decisions is not somehow "given" to the decision-makers. Whether they are customers or generators or transmission planners, decision-makers need to make judgements based on observation and extrapolation of actual behaviour in response to prices. Implementation of the TPM to previous investments provides more information than would otherwise be available.

10. Suppose an industrial user is considering where to locate a new plant, or a generator is considering whether and where to build generation. These market participants may or may not have heard that there will be benefit-based locational pricing in the future, but they may not know what that might mean. Implementation of the TPM to previous investments will provide, not perfect information, but better and sooner information than the user previously had, about the possible extent of price changes, and in which areas of the country they will increase and decrease.

11. Suppose a transmission planner is considering whether to extend the transmission system. Benefit-based locational pricing is to be introduced in future, but what if any effect will it have? Suppose the TPM is implemented on previous assets. Then there is an immediate change in prices, and an earlier indication of whether or not this makes a significant difference to household and industry consumption decisions.

12. Again, it is not claimed that the information that becomes available as a result of applying the TPM to previous or legacy investments is "perfect", or that immediate price changes will precisely mirror the changes that will take place over time as a result of new investments. It is simply argued that information to customers, generators and transmission planners will be better than it otherwise would have been, and that this will improve the efficiency of the New Zealand electricity supply industry.

13. This is a point that the EA adduced in favour of its proposal (e.g. at page v, para B54 page 118 and para G53 page 253), and with which Professor Bunn did not take issue.

14. The second question is whether it is justified to exclude certain legacy investments. This seems to be a matter of practicality rather than principle. The EA argues that it is not appropriate to apply the TPM to investments that are so small that any benefits, in terms of changed pricing signals that might result, are so small that they are outweighed by the costs of implementation. This seems sensible.

15. Now consider whether it makes sense to apply the TPM to larger investments where it seems, in retrospect, that the benefits to the beneficiaries are less than the costs of the investment? A regulator has to be aware of the concerns and objections that might result given the lack of net private benefits. If it is acknowledged that an investment was not worthwhile from the point of view of the intended beneficiaries, it is just not worth the hassle of trying to defend the proposition that these beneficiaries should bear costs in excess of the private benefits they derive from the investment. It is more sensible to concede that the costs of such investments should be spread more widely.

16. Professor Bunn further argues that "including 7 legacy investments in the beneficiaries charging … undermines confidence in the regulatory regime going forward". The precise reason for this is not spelled out but may be based on his claim that "dynamic efficiency may be eroded somewhat by an increased regulatory risk premium in investments going forward". (p 7)

17. In my previous paper I argued, to the contrary, that investors would have expected a regulatory regime to be looking to transform the sector over time and, in particular, to develop transmission pricing and other arrangements to be more consistent with what one would find in the private rather than public sector. Given that the EA is moving towards prices that better reflect costs and benefits, it is hard to see how investors would be less confident in the regulatory regime. On the contrary, investors would see a regulator confidently and competently adapting to a more competitive market, and going through due process and taking all reasonable steps to ensure that it understands the issues and implications for investors as well as customers and other market participants.

The role of a prudent regulator

18. I am asked to opine on "the role of a prudent regulator in a situation where there is broad acknowledgement of problems with the existing transmission pricing arrangements but conflicting views amongst industry participants as to the best solution".

19. It seems to me that a prudent regulator in such a situation would follow due process of the following kind: indicate the nature of the concerns about this problem, invite views on that, form an initial view of a potential solution, consult on that, modify the initial view and proposals as appropriate to address the main concerns, consult again, modify the previous view as appropriate, and implement the preferred solution.

20. My impression is that the EA has done this. For instance, the EA has undertaken significant consultation over a number of years. It has addressed problem definition in several rounds of consultation including in the first issues paper (2012), a dedicated working paper on problem definition (2014) and again in the second issues paper (2016) and the current consultation round (2019). It has modified its initial views about the nature of the proposal to address those problems. Following further rounds of consultation on key aspects of the proposal the EA has settled on a proposal retaining the existing connection charge, and replacing the interconnection and HVDC charges with a benefit-based charge and a residual charge on load. It is again consulting, on this specific proposal. Following its consideration of submissions and other material presented on the proposal, it is time for the EA to implement its preferred solution. To prolong discussion unnecessarily is costly to all parties, and prolongs or increases uncertainty as to what the ultimate outcome will be.That increases costs and risks for market participants generally.

21. The regulator has to consider the balance between hearing and responding to interested parties, and implementing the preferred arrangements. After a decision seems to be in prospect, the more time that is taken up with listening to objectors, the longer it takes to deliver the benefits of the proposed policy.

22. There is another relevant issue. The credibility of the regulator and the regulatory policy may be at stake. Market participants may come to doubt whether the regulator is able and willing to implement the policy under consideration.

23. In the present context, further prevarication could lead to customers and generators asking themselves: is this proposed change in transmission pricing policy really going to happen? Is the regulator going to have the confidence to implement it? If we invest on the assumption that these changes take place, shall we be regretting it in a few years time? And even if the regulator does go forward with these policies, will it be able to sustain those policies in the event that there is a backlash against them? Will customers and generators really be willing to tolerate the differential prices that might emerge from the new policy applied to new investments? And if opposition is strong, will the regulator be forced to compromise and modify or withdraw this policy?

24. In contrast, if the regulator were to implement the TPM proposal, this would mean application of differential prices reflecting the historic investments in the near future. It would soon become apparent whether these prices were socially or politically problematic and whether the regulator was able to maintain support for them, and for the prospective price changes in the years ahead.

25. For these reasons it seems to me that the EA has taken appropriate steps to understand the issues and problems for the various parties, and to make such modifications as seem appropriate to address concerns. Having come to that view, it is now time to implement the proposed policy rather than to delay and invite further objections.