Electricity Authority
Via email: submissions@ea.govt.nz

1 October 2019

Consultation Paper – Transmission Pricing Review: 2019 Issues Paper

Mercury welcomes the opportunity to comment on the Electricity Authority's (EA) 2019 Issues Paper on the development of the Transmission Pricing Methodology (TPM).

Mercury has previously supported a prospective application of beneficiary-pays giving transmission customers the incentive to participate in Transpower's investment decisions. Based on the analysis provided in the issues paper, which shows no difference between applying beneficiary-pays prospectively or to prospective investments and certain existing investments, we remain convinced there is no benefit reallocating costs to sunk assets.

The key concern for the EA remains that the TPM is not thought to be durable unless some historical costs are reallocated. However, any assessment of beneficiaries is a modelling outcome rather than an objective exercise, as evidenced by how the assessment of beneficiaries has shifted with various proposed TPM iterations. Reallocation of historical costs will create the incentive to dispute TPM charges in future, undermining the EA's goal of durability.

Another durability challenge is the fact that transmission revenues are set to fall by as much as 30% in the next five-year regulatory control period for Transpower commencing in 2020[1]. This will result in a substantial fall in charges for many parties lobbying for reform of the TPM. Any additional cost re-allocations that cause charges to then rise for other parties under a new TPM will be viewed as unfair and create incentives to contest the TPM.

North Island geothermal generators have seen beneficiary charges double since the 2016 proposal for example despite the EA applying mostly the same approach. Mercury considers durability is not an issue that the EA can easily resolve and supports the recommendations from the Electricity Pricing Review's Options Paper for Government to provide a policy statement on who should benefit from TPM reform.

Mercury agrees that future renewable generation investment will be required to deliver New Zealand's climate change goals. However, the existing TPM is not an impediment to South Island renewable generation investment. Material differences in nodal prices and the risk of the Tiwai Aluminium smelter closing are the most significant factors. Shifting toward beneficiary-pays will not resolve these issues. Perversely, there is a risk historical cost reallocation may in fact act as a deterrent to future North Island geothermal investment.

We agree some of the problems identified in the issues paper are valid, but the same net benefits could be delivered by revising the existing TPM or introducing elements of the EA's proposal. The EA makes some useful suggestions in the paper which Mercury considers warrant further consideration as discussed in section two below.

[1] Due to significant falls in financing costs that affect Transpower's weighted average cost of capital set by the Commerce Commission.

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1 Problems identified with the existing TPM

1.1 Inefficiencies related to the interconnection charge

1.1.1. Mercury agrees the current peak pricing approach under the interconnection charge of the TPM can create inefficient incentives to reduce consumption and to invest in distributed generation or storage to avoid transmission charges. Resolving these inefficiencies accounts for the majority of benefits the EA perceives from implementing its current TPM proposal.

1.1.2. However, in Mercury's view, these inefficiencies could be resolved more simply by changing the existing TPM or by implementing elements of the EA's preferred approach. Transpower has previously proposed operational changes to the TPM to address this issue (e.g. by shifting to a MWh charge), an approach supported by many submitters[2]. The EA acknowledges such an approach would be more efficient than the current TPM (and even quantifies the net benefits at $1.8bn) but discounts this option on the basis that new investments would not be allocated according to benefit. However, this could be resolved through a prospective implementation of beneficiary-pays (see section 1.2).

1.1.3. The other main reason the EA seems to discount changing the interconnection charge is that an opportunity would be missed to improve location incentives for investors in generation. Mercury does not support the view that transmission charges have a material impact on generation location decisions[3]. This is primarily because generation must be sited at the location of the best fuel resources, particularly where those resources are renewable. Other factors such as resource consenting are much more significant factors influencing locational decisions. We discuss these factors further in section 1.3 below.

1.2 The TPM is not durable as current charges are not aligned to benefits

1.2.1 One of the key debates throughout the TPM consultation process has been whether any benefit-based charges should seek to re-allocate historical transmission costs or whether these should apply only to future transmission investments. The EA's view is that some limited reallocation of historical costs is justified, as failure to align charges with benefits has led to constant lobbying to change the TPM.

1.2.2 Mercury appreciates this is a difficult decision with various pros and cons. The discussion paper provides a useful consideration of various alternative options to historical cost reallocation. These include introducing a future-only beneficiary-pays charge and recovering the costs of current investments through either the residual charge or through some fixed allocation of the existing interconnection and HVDC charges[4].

1.2.3 Mercury does support the theory there may be some (limited) efficiency gains from allocating future investment costs according to an assessment of beneficiaries, as long as that assessment was linked to the major transmission investment approval process and there were reasonable, majority-based decision rights for participants to oppose or defer transmission investments from which they were unlikely to benefit.

1.2.4 By the EA's own cost benefit analysis, there are no material differences between the proposal or by applying beneficiary-pays only on a prospective basis[5]. The EA also notes that reallocating historical costs has not been a feature of any overseas beneficiary-pays systems.

[2] Refer section E.96
[3] See s2.1.26 of MRP's Submission to Electricity Authority's TPM: Issues and Proposal Consultation Paper - 1 March 2013
[4] Refer section B.43 onwards
[5] Refer section 4.172

1.2.5 Given the expected benefit for either option is the same, the EA's remaining support for reallocation of historical costs is to address the durability concerns with the current TPM. However, no value for this benefit has been calculated in the cost benefit analysis as the EA considers it too difficult to be accurately assessed.

1.2.6 Mercury has consistently argued that durability benefits from the reallocation of historical costs are highly unlikely to eventuate. This is because there are no objective and unambiguous methods to accurately estimate beneficiaries in retrospect. Any ex-post estimation of beneficiaries is simply the output of modelled assumptions and cannot be treated as factual and incontrovertible.

1.2.7 As an example, the 2019 analysis was not able to identify any material benefits for transmission customers of the North of Auckland and Northland (NAaN) upgrade commensurate with the cost of this investment[6]. In contrast the 2016 analysis estimated the benefits associated with the NAaN upgrade to be equivalent to $39m per annum[7]. Given the impacts to Northland consumers from TPM reform Mercury considers it pragmatic that the NAaN upgrade has been excluded from the beneficiary assessment. However, with costs of the NAaN now proposed to be recovered under the residual charge this will create the same incentive for participants to dispute the TPM in future. Therefore, the same durability issues with the current TPM also apply to the proposed TPM.

1.2.8 One key factor not given enough attention in the consultation paper, but with a significant bearing on transmission costs (and potentially the durability of the TPM), is Transpower's regulated returns. For the regulated control period between 2020 and 2025 the Commerce Commission has indicated there will be a significant decrease in Transpower's regulated cost of capital and therefore its permitted revenue[8]. The discussion paper highlights that revenue from the HVDC link alone is set to reduce from $145m p.a. currently to $99m p.a. in future years – a decrease of around 30%.

1.2.9 Given the above, without any intervention at all from TPM reform, participants who have lobbied for changes to the TPM will see a significant reduction in historical transmission charges. Any further benefits from the historical reallocation are likely to viewed as unfair by those who will see their charges increase.

1.2.10 Mercury notes that North Island geothermal generators, many of which are joint ventures with Maori land trusts, have had modelled beneficiary charges double since the EA's 2016 TPM proposal while others, particularly South Island businesses, will realise substantial reductions. This is challenging as the country enters a period where the contributions from renewable generation, and particularly geothermal as the only non-intermittent renewable generation source, is expected to increase. It will also impact directly on the health and education grants paid out by Maori land trusts to their owners and descendants, exacerbating perceptions of unfairness.

1.2.11 Mercury considers that any cost reallocation process involves winners and losers which must ultimately become a political decision rather than one that can be resolved empirically. The Government's Electricity Pricing Review's Options Paper recognised this inherent tension in the recommendation for a government policy statement on transmission pricing to clarify who it considers should be the beneficiaries of transmission pricing reform. Mercury supported this recommendation and suggests such a statement may be helpful to resolve the perceived durability issue raised by the Authority.

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[6] Refer section B.147

[7] See TPM Second Issues Paper (2016) - Table 7 page 213 "Investments modelled as being subject to the area-of-benefit charge"

[8] See https://comcom.govt.nz/news-and-media/media-releases/2019/commission-releases-key-inputs-for-transpowers-price-quality-path

1.2.12 Mercury also supports the EA considering the merits of implementing the option proposed in section B.48 of the discussion paper:

> "…apply the benefit-based charge only to future grid investments and recover other costs from the parties that currently pay transmission charges, in proportion to their current payments. This could be arranged via an alternative specification of the residual charge (payable by all transmission customers) that was allocated in fixed proportions (determined by fixing the current allocation of RCPD and HVDC charges)…. Distortions to grid use would be avoided, as charges would be fixed (as opposed to varying according to grid use as with the RCPD and HVDC charges). Revenue recovered from load and generation customers via this alternative residual charge would reduce over time with depreciation."

This option would give participants certainty that their charges would decrease over time and would avoid the durability, consumer impacts and generation investment issues associated with the reallocation of historical costs.

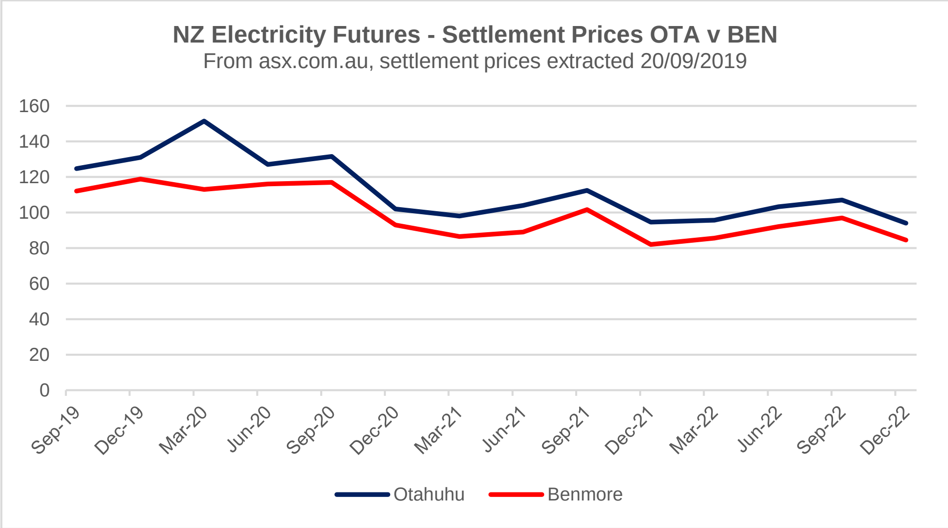
1.3 The current HVDC charge distorts the cost of South Island generation investment

1.3.1 The issues paper argues that the current HVDC charge effectively taxes South Island generation and that it is material enough to disincentivise investment, leading to higher costs for New Zealand consumers. The EA deems this circumstance material enough to change the TPM, particularly considering the need for the market to deliver significant renewable energy investments as part of achieving the Government's climate change goals.

1.3.2 Mercury agrees that future renewable generation investment will be required to deliver New Zealand's climate change goals. However, we disagree the existing TPM is an impediment to South Island renewable generation investment and New Zealand renewables uptake in general.

1.3.3 Wholesale prices in the South Island have been, and are expected to be, persistently lower (~$10/MWh) than the North Island (refer to graph on the following page of future prices). This reflects the fact the South Island is predominantly a generation-export region and that there are losses associated with transporting that excess electricity to load in the North Island. This factor alone would be enough for investors to favour North Island generation investment. Project economics would heavily favour the North Island at an additional $10/MWh.

1.3.4 However, Mercury considers the uncertainty and impact from a potential exit of the Tiwai smelter (at 14% of New Zealand's demand) overhangs potential South Island investment. Under a Tiwai exit scenario, significant transmission investment would be required to re-configure transmission infrastructure in the South Island and augment the HVDC link to allow for greater northward electricity flow. This process would take several years during which time the South Island generation market would be substantially oversupplied, rendering any recent generation investments uneconomic. Given a generation investment will have to earn at least its cost of capital over a 25+ year timeframe, the economic losses associated with a Tiwai exit scenario prevent any credible business cases for large-scale generation investment in the South Island. This would be an unacceptable risk to shareholders.



1.3.5 For this reason, Mercury also considers that shifting toward beneficiary-pays for the HVDC link will not be a sustainable solution to the “tax” issue the EA has identified, even if this were a material factor for generation investment. Under the EA’s proposal, the Tiwai exit scenario would be considered a material change in circumstance. At this point South Island generation owners would unambiguously become the main beneficiaries of the existing transmission network as well as any costly future transmission and HVDC upgrades required to export generation to the North Island.[9]

1.3.6 Regardless, investors will still be deterred by the wholesale market impacts from a Tiwai exit scenario rather than the potential re-allocation of transmission costs in Mercury’s view.

1.3.7 Over the past decade Mercury has been deeply involved in consenting potential future renewable electricity generation sites across New Zealand. Central to the economics for wind generation is securing high quality wind sites and then optimising for the best available yields given the technology options available within the planning envelope agreed through the environmental consent process.

1.3.8 Achieving environmental consent has proven to be a significant limiting factor for wind farm developments, particularly in the South Island. Meridian’s proposed windfarm in central Otago, Project Hayes, was shelved due to the concerns with the landscape impacts which were unable to be resolved through Environmental Court appeal.

1.3.9 Meridian’s chief executive at the time, Mark Binns, was quoted as saying: "Withdrawing the consent applications is not only the most prudent commercial decision for Meridian, but also avoids prolonging uncertainty about this project for the community and the project's supporters”[10]. The Government is currently considering what options may be available to remove any barriers for future renewables investment with the consenting process as part of its proposed renewables strategy.

1.3.10 Mercury’s recently announced Turitea windfarm development in the lower North Island has among the best capacity factors of any wind location, not only in New Zealand but internationally. This reinforces Mercury’s view that increased locational signalling via transmission pricing reform would not have changed Mercury’s decision to invest in the North Island – access to the renewable resource was the most significant factor.

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[9] Mercury questions in such a scenario if existing South Island generators would then willingly accept the beneficiary allocation of the likely infrastructure needed to extend from Manapouri to Auckland. This argument adds to our points in section 1.2.
[10] See Otago Daily Times “Meridian Pull Plug on Project Hayes” (2 February 2012) https://www.odt.co.nz/regions/central-otago/meridian-pulls-plug-project-hayes

1.4 The TPM provides poor incentives to scrutinise grid investment proposals

1.4.1 Mercury agrees the transmission planning process could theoretically be improved with prospective implementation of beneficiaries-pay subject to the provisos outlined in s1.2.3 above. Mercury's issue with the reallocation of historical costs has been that it is not linked to the transmission planning process, instead relying on a modelled assessment of market offers. At best this has been controversial. Beneficiaries have no ability to retrospectively influence transmission decisions or to recover the costs of reallocation.

1.4.2 Mercury has also raised questions in previous submissions as to the value of allocating significant beneficiary-pays charges to generators who do not require the same level of reliability of the transmission grid as end-use consumers. This may create incentives for generators to oppose transmission investments that are in the long-term interest of consumers. See our response to question 1.4 for further discussion.

2 Supported options for reform

TPM issue	Mercury View	Suggested reform option
Current interconnection charge is inefficient	Agree but does not require reallocation of historical costs to resolve	Support a Transpower operational review of the existing interconnection charge including assessing moving toward a MWh charge and the option of implementing the EA's proposed alternative (at para B.48) to apply beneficiary-pays prospectively, introducing an alternative residual charge with fixed allocations for current allocation of RCPD and HVDC charges. This will also assist in addressing durability issues.
The TPM is not durable as current charges are not aligned to benefits	Disagree that reallocating historical costs will lead to a durable TPM	Implement the EA's proposed alternative above to fix existing charges and phase them out with depreciation of the assets. Support the Government in issuing a policy statement of who the beneficiaries of TPM reform should be. Make clear that changes to Transpower's regulated rate of return will result in material decreases in transmission charges (~30%) in the forthcoming five-year regulatory period.
The current HVDC charge distorts the cost of South Island generation investment	Disagree – nodal price differences and impacts from Tiwai exit scenario are more material factors	No action required but HVDC impacts could be reduced through implementation of the EA's alternative option as per above.
The TPM provides poor incentives to scrutinise grid investment proposals	Agree	Implement prospective application of beneficiary-pays linked to Transpower's major transmission investment approval process with reasonable, majority-based decision rights for participants to oppose or defer transmission investments for which they expect minimal benefit or disbenefits.

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Yours sincerely,

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3 Appendix 1. Responses to consultation questions

Question	Mercury's response
I.1 Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?	No. We outline our views in section 1 of our cover note to which we provide additional detail below. Mercury agrees with the EA that the current RCPD charge can distort the way the grid is currently used and accept that this can lead to inefficient outcomes. We do not accept the logical next step is a full review of the TPM. Rather, it would make sense to firstly consider whether the existing RCPD charge could be amended. This would be the most efficient and low-cost outcome for the industry and could be achieved by way of Transpower carrying out an operational review of the RCPD. Though we doubt the magnitude, we note the considerable net benefit achievable, as modelled by the EA in its alternative CBA scenario, by increasing the number of trading periods for the RCPD charge. This does not require a large-scale reform of the TPM. Further, the EA outlines some alternative proposals to replacing the RCPD and HVDC charges that Mercury considers merit further consideration (see Section 2 of our cover letter). We do not agree with the EA's analysis of problems with the current HVDC charge as discussed in section 1.3 above. Transmission represents a small part of any generation project and would only determine the most marginal of investment projects. New Zealand's large-scale renewable generation projects are constrained mostly by access to fuel resources and the ability to achieve environmental consenting. The EA does not seem to consider that economic investments have occurred in the South Island (Mahinerangi) under the current TPM or that South Island projects were proposed and did not proceed for reasons unrelated to HVDC charging (Project Hayes, Waitaha). South Island load, and particularly under a Tiwai exit scenario, is too low to justify large generation projects especially compared to relatively more economic North Island projects. Mercury notes that Meridian has information on its website on four consented generation projects, two in the North Island and two in the South Island. Meridian has "no plans to construct" its South Island projects due to "low demand growth for electricity." In addition, of the 2372 MW of consented wind generation per the Wind Energy Association's website[11], only 23% of the capacity is in the South Island. Looking at the futures market, there is persistent price separation between Benmore and Otahuhu prices. This price separation is not simply a factor of transmission pricing but rather represents the underlying economics of South Island net energy export and North Island load demand. The North Island has enough energy capacity to be self-sufficient. Irrespective of transmission pricing, the South Island is an energy exporter most of the time and would be all the time under a Tiwai exit scenario. This price separation makes project economics for North Island generation development significantly more attractive vis-à-vis South Island generation development. This is a far more compelling reason for the lack of generation development in the South Island than is the relatively small annual charge for the HVDC. HVDC charging is a static cost allocation exercise and we do not expect any material benefits to arise from reapportioning its charges. We also note that Transpower, in its operational review, was able to deliver a positive outcome for the industry by modifying the existing TPM. We therefore do not consider the EA has correctly identified a problem, or if it has, has not sufficient tested if it could be addressed in the existing TPM in a lower cost manner (for example by fixing the allocation to South Island generators as the EA has suggested). One further issue Mercury has is that under beneficiary pays it is highly likely project economics become even worse in the South Island relative to the North Island. Noting that the South Island is primarily an energy exporter, any large-scale generation development projects will require augmentation to the HVDC. As such investments are unlikely to be near Benmore, the prospective investor is likely to require a substantial investment in localised transmission and require an upgrade to the HVDC link. Under beneficiaries pays, that investor is likely to bear the majority of charges for that transmission, rather than having it socialised more widely by the current interconnection charge (or increased HVDC charge).

[11] Refer http://www.windenergy.org.nz/consented-wind-farms

I.2 What are your overall views on the Authority's proposal for changes to the TPM guidelines?	Refer to our views expressed in the cover letter and in response to question 1. In summary, we do not accept the problems identified justify wholesale reform of the TPM or that smaller scale alternatives within the existing TPM have been exhausted. Mercury strongly favours reviewing the existing RCPD charge under the existing TPM which we think could be implemented quickly, would come at much lower implementation cost and disruption to participants, and would create efficiency benefits to the industry.
I.3 Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?	From an analytical perspective, Mercury is doubtful the overall net benefits from the proposal could be as high as $6.4 billion. Comparing this to the net benefit from the 2016 proposal of $0.2 billion, the high end 2019 proposal is 30 times the expected net benefit for what essentially the same proposal. In comparison to the alternative proposal, or a review of the existing RCPD charge, the EA assumes an additional c. $1 billion of net benefit for its preferred approach. The primary reason is the additional South Island generation assumed in the proposal will not occur as quickly. As discussed in section 1.3 and response to question 1 we think the EA's analysis of HVDC and South Island generation overstates the supposed merits of South Island generation. We are unable to find any public information on South Island generation projects being abandoned because of HVDC charges alone which indicates this cannot be a determining factor of location decisions. Notwithstanding the above, we acknowledge the difficulty in preparing the CBA model and we appreciate the EA's efforts to consult with industry on the methodology in the Wellington technical briefing. While the methodology seems sensible, we recommend the assumptions used in the model be given careful review. Mercury intends to provide a more detailed response in its cross submission but questions if there is merit in the EA having the assumptions independently reviewed and that review be shared with the industry. This could reduce the amount of CBA related focus the EA is likely to receive in submissions. By way of feedback at this stage, Mercury notes the following: • Mercury has never been a proponent of relying on vSPD for the type of modelling the EA has done. Too many assumptions are required, including the extrapolation of historical offers to a stylised future scenario. Similar reservations have been raised by numerous submitters through the TPM process; • We query the need to create a CBA at this point given the EA would need to evaluate costs and benefits again for any Transpower proposed TPM; • Though potentially difficult to model, we consider the EA's proposal could have a significant cost impact on vulnerable consumers, particularly in the upper North Island. Even marginal increases in costs can lead to a negative spiralling effect for these consumers; • Given transmission pricing represents around 10% of a mass market energy bill, compared to reforms to distribution pricing (at 25-30% of the bill) we believe more cost reflective transmission charges will have minimal impact on the change in household energy use, certainly not to the extent the EA has modelled; • We strongly doubt the EA's modelled exposure and ability of mass market customers to respond to real-time pricing will increase to 50% by 2032. Also, while some customers will want a cost-reflective tariffs, there will be a significant proportion of the population who will continue demanding a FPVV style tariff given the certainty this provides; • The EA's modelling seems to assume that there will be increased long term demand for energy as a result of a new TPM and that this increased demand, at lower prices, will be met with generation built at lower prices. This assumption seems questionable to us as generation investment is unlikely to respond to decreasing price signals.
I.4 Do you have any comments on the matters covered in chapter 4?	Refer to our responses to question 3 above. In addition to the comments above, we are not convinced of the benefit of the 'scrutiny of grid investment' ($77m in the CBA). Mercury has raised in previous submissions that generators require a lower standard of grid reliability than end-use consumers. This differential is acknowledged in the relative reliability benefits used in the EA's CBA of $200/MWh for generation compared to $20,000/MWh for consumers (section 4.50 of the paper). As the majority of transmission investments are approved to improve reliability (rather than wider economic benefits from lower wholesale costs or improved competition) allocating significant beneficiary charges to generators for shared interconnection assets

	designed to improve reliability for consumers could potentially work against the long-term interests of consumers. This is because generators would be incentivised to oppose investments due to the lower value they attribute to transmission upgrade to the shared network. This risk and potential cost are not quantified in any way that Mercury can see in the CBA and is not an issue under the current TPM.
I.5 How long should Transpower have to complete its development of the TPM and why?	To the extent the EA proceeds with its proposal, we agree it is necessary for Transpower to carry out a robust consultation process with the industry. Any timeline needs to acknowledge the substantial investment in resource required of Transpower in developing the TPM. We favour the EA working with Transpower on a realistic timeline.
I.6 What checkpoints (if any) should the Authority set in the TPM development process?	No comment
I.7 How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?	Mercury supports regular industry consultation on the proposal but considers the design should be left to Transpower. As the core of the proposed TPM is the beneficiary-pays modelling, we welcome Transpower consulting on ways to best model the wholesale market to identify beneficiaries rather than the EA mandating the use of its own modelling (e.g. as for Schedule 1).
I.8 In addition to the specific questions above, do you have any further comments on the matters covered in chapter 6?	No comment
I.9 What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?	We have some comments on the Guidelines below, which are consistent with our views on not applying beneficiaries pays to historical investments and also removal of the PDP. We do query why Guidelines are needed at this point given the paper is an "Issues Paper"; presumably the policy settings for any TPM proposal are not yet settled. We welcome the opportunity to review the Guidelines if and when the policy settings have been finalised. • Amend the Policy Objectives to remove all references to "existing investments" in the interconnected grid • Amend the Guidelines to remove all reference and requirements for the Prudent Discount Policy • It is not clear to us why the connection charge must include a definition of 'deep connection' (s. 11) • Removal of sections 13(b) and 13(b) from the Guidelines • Removal of section 14(a)(ii) from the Guidelines • Amendment of s14(d) to "any other costs **directly** attributable to that benefit-based investment" • Removal of s16 from the Guidelines • Removal of requirements throughout for Transpower to use Schedule 1
I.10 Do these provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?	We agree with the need to give Transpower flexibility in developing the TPM. Any TPM will have its durability undermined to the extent the Guidelines do not allow for ease of implementation and operability.
I.11 Should the current guidelines on connection charges be largely retained or are changes required?	Mercury supports the retention of the existing connection charge regime.
I.12 Should first-mover disadvantage be addressed in the TPM, and if so, how?	Mercury does not support this being progressed with the current TPM review.
I.13 Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?	Refer to our comments in section 1.4 of the cover letter. Mercury considers there could potentially be benefits from a prospective application of beneficiary-pays subject to a number of provisos. As outlined in our response to Question 4, allocating significant beneficiary charges to generators for reliability enhancing interconnection investments could be detrimental to the long-term benefit of consumers.

I.14 Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?	As discussed in our cover letter at section 1.2, we do not support the reallocation of historical investments should be recovered through beneficiary-pays. We support the EA considering the merits of implementing its proposed alternative specification of the residual charge as outline in section B.48 of the paper. We agree with the analysis in the report commissioned by Trustpower in 2017 from Bushnell and Wolak which notes "a tariff structure intended to improve future investment decisions has no relevance for the recovery of existing asset costs" and the authors "are absolutely certain that it [applying charges to historical assets] cannot improve past investment decisions."[12] Making ex-post changes to sunk investments risks creating perverse outcomes such as the issue related to North Island geothermal development outlined at section 1.2.10 of the cover letter. These points contradict the recommendations Professor Hogan made to the EA as mentioned in B51/B52 of the paper.
I.15 Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?	Mercury does not support the application of beneficiaries pays to any historical investments as discussed in section 1.2 of our cover letter. See our response to the previous question.
I.16 How should the covered cost of the investment be defined?	No comment.
I.17 How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method?	Refer to our comments throughout and in the responses to questions 7, 9 and 14. If a historic approach is to be pursued Mercury would support greater discretion for Transpower to determine the method.
I.18 Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?	Our preference is for this to be based on a net load approach, but we support giving flexibility to Transpower to decide.
I.19 Should the guidelines distinguish between high-value and low-value investments?	Mercury agrees there is merit in splitting between high and low value investments and supports all low value investments being recovered through the residual charge.
I.20 If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?	Mercury supports all existing transmission investments being recovered under the residual charge.
I.21 What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?	We consider a $20 million threshold is appropriate.
I.22 What are your views on the Authority's proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?	Mercury does not support the application of beneficiaries pays to any historical investments, so the benefit allocation per Schedule 1 is redundant in our view.

[12] Bushnell, J. and Wolak, F. (2017), *Beneficiaries-pay pricing and "market-like" transmission outcomes*, paper sponsored by Trustpower available from: https://ea.govt.nz/dmsdocument/21898-trustpower-appendix-e-bushnell-wolak-18-feb-2017-v1-0

	Notwithstanding if the EA is determined to progress historical reallocation we would support Transpower developing a methodology for determining the beneficiaries of transmission investments with industry consultation. We are not in favour of using VSPD to determine future (or historical) beneficiaries. We support the EA considering its alternative implementation of the residual charge rather than reallocating historic costs as discussed in response to question 14.
I.23 How should the costs of the investments that are not covered by the benefit-based charge be allocated?	We support the intent of the residual charge but as noted the same quantum of benefits could be achieved through incremental improvements to the existing interconnection charge within the existing TPM (including through a shift to a MWh charge or the EA's alternative implementation of the residual charge (see response to question 14)
I.24 Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?	Yes, we agree there should be a revision to charges if there has been a substantial change in grid use. We believe this is something Transpower would be best placed to develop. Our only point here is that any changes should be clear, and preferably phased in for remaining beneficiaries for a particular investment.
I.25 Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?	Mercury's view is that low value investments should be recovered through the residual charge, so there is no need to defer implementation.
I.26 Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge? What are your views on the proposed reassignment provisions?	Refer to our response on question 24.
I.27 Should the guidelines provide for a single residual charge or multiple residual charges?	Mercury support consideration of implementing the option proposed under section B.48 of the paper which would entail fixing the allocation of the current RCPD and HVDC charges.
I.28 Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?	No comment.
I.29 Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?	We welcome Transpower developing the best option in consultation with the industry.
I.30 If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?	We welcome Transpower developing the best option in consultation with the industry.
I.31 Should demand be measured using a net load or gross load approach for the allocation of the residual charge?	Though we welcome Transpower developing the best option in consultation with the industry, our initial preference is for a net load approach as this better reflects actual use of a transmission circuit.
I.32 If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?	Refer to our response to question 31.
I.33 Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?	No comment.

I.34 Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?	The allocation should fall out of Transpower's application of the Guidelines, so no we do not support the EA determining the initial allocation of residual charges.
I.35 Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?	This seems reasonable, provided there is a clear justification or change trigger. Ideally any changes should be phased in or delayed until the next allocation of charges to minimise disruption to others.
I.36 Should the residual charge apply to both generation and load customers, or only to load customers?	Mercury agrees with the EA that the residual charge should only apply to load.
I.37 Are the proposed provisions relating to adjustments appropriate?	Yes, these provisions are reasonable.
I.38 Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?	Mercury does not favour including the prudent discount policy in any form. We think such a regime is likely to be gamed and will add unnecessary cost and distractive processes for Transpower and the EA which are likely to require making judgments on areas outside of expertise.
I.39 Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?	Mercury can see some merit in using a temporary cap if it helps ease transitional transmission costs to all transmission customers, including distributors and generators. It seems the only beneficiaries under the proposed cap are large industrial users.
I.40 Should the price cap be specified as a percentage of electricity bills or in some other way?	No comment.
I.41 Should the price cap apply only to load customers, or to generators as well?	Refer to our response to question 39.
I.42 How should the price cap be funded?	No comment.
I.43 Are the proposed additional components appropriate? If not, what changes should be made?	Mercury does not have any view on these additional components, other than to support giving Transpower discretion on their implementation.
I.44 Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?	We are happy to accept the phased-out application of a peak charge if Transpower deems that a useful component. We do not think it should be mandatory.
I.45 Should the peak charge be applied only where the grid would otherwise be congested?	Refer to our response to question 44.
I.46 Should the peak charge be permanent, or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?	Refer to our response to question 44.
I.47 Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?	No. Mercury does not support the application of a benefit-based charge to investments made prior to the implementation of a new TPM. The charge should only apply prospectively. See our comments in section 1.2 of the cover letter.

I.48 In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?	No.
I.49 Do you have any comments on the matters covered in this appendix C?	See our comments in section 1 of the cover letter which provide Mercury's view on the material problem definition areas as identified by the EA.
I.50 Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?	See our comments in section 1.2. The main issue we have with the analysis is that any ex-post estimation of beneficiaries is simply the output of modelled assumptions and cannot be treated as factual and incontrovertible. Despite using effectively the same approach as in 2016 there has been a material swing identified beneficiaries which Mercury considers will be an ongoing source of dispute for the TPM.
I.51 Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?	We don't find the analogy particularly helpful or relevant as transmission investment is clearly a monopoly issue rather than a competitive market issue. Mercury has never understood why the EA considers the well accepted economic principles of efficient monopoly pricing such as Ramsey pricing are insufficient to treat sunk and historic transmission costs. In this regard the EA has correctly identified there are issues with the current RCPD price signals that may be inconsistent with Ramsey pricing, but this could be relatively easily resolved via incremental improvements to the TPM or through other suggestions made by the EA (See section 2 of our cover letter). It appears that the main rationale for the EA's insistence on applying a workable competitive framework is to get around the constraints of accepted economic theory and allow for the reallocation of sunk historic costs and resolve the durability of the TPM. For the reasons outlined in the question 50 above Mercury does not consider this can be achieved.
I.52 Do you agree with the conclusions of appendix D?	No. Mercury cannot understand how the EA continues to consider the TPM will have a material bearing on future transmission investment. The TPM has no influence on the decision to approve a transmission investment which is undertaken by a separate regulator in the Commerce Commission and under a separate set of criteria. The EA's view that reforms to the TPM mean that "a new investment need not be precipitated by such matters as demand growth or grid reliability unless those considerations provide an economic justification for the investment." cannot be substantiated by Mercury. Transmission investment will always be lumpy in nature given the significant economies of scale and material challenges associated with securing landowner access agreements. It will therefore always remain the case that, absent perfect foresight, the regulator will be inclined to favour early and large-scale investments or else run the risk of reduce reliability which can have enormous economic impacts for consumers. At the margin a beneficiary-pays approach may incentivise greater participation in the transmission approval process, but this will not materially improve the assessment of future electricity demand which is inherently uncertain. Without careful design it could in fact delay the decision-making process or cause parties who do not privately benefit to oppose investments that would in fact be of benefit to consumers. Given the majority of transmission investments to date have been approved for reliability purposes Mercury cannot see how a revised TPM would materially change this process given the Commerce Commission would not be required specifically to be influenced by what is a cost-allocation framework.
I.53 Do you have any comments on the matters covered in this appendix D?	No.
I.54 Do you agree with the conclusions we draw from Transpower's report *The role of peak pricing for transmission*?	No comment.
I.55 Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?	No comment.

I.56 Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?	We partially agree. We think the Commerce Commission regulatory regime and nodal pricing are sufficient to ensure efficient investment in the grid. As a regulated monopoly business, pricing for grid use is a secondary consideration to the primary consideration of how much grid to build and the quality of that grid. The pricing aspect of grid use is unrelated to the investment aspect and the EA should be careful to not influence it by way of the Guidelines, particularly as this is the remit of a different regulator. See our response to question 52.
I.57 Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?	No comment.
I.58 Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?	No comment.
I.59 Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?	No. See our responses in section 2 for our views.
I.60 Do you have any comments on the matters covered in this appendix E?	No comment.
I.61 Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?	We understand the EA is considering a separate code change proposal on the treatment of LCE from market participants and support that process being progressed ahead of any TPM reform. We support that process progressing first.
I.62 Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be efficient?	Mercury agrees the ACOT provisions in the Code may need to be amended but has no view at this stage on what those should be. We agree there is no need to process this Code change concurrent with any TPM reform, noting it will be several years before a new TPM is in place.
I.63 Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?	Mercury does not support this amendment as it is unnecessary. It could also potentially lead to significant uncertainty in the operation of the TPM.
I.64 In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?	No comment.
I.65 Do you have any comments on the matters covered in this appendix G?]	Our only comment is that over the last decade the EA appears to have favoured a predetermined outcome for TPM reform without seriously considering less interventionist options for improvement, as achievable by Transpower within the existing TPM for example, or with minor tweaks to the existing guidelines. Mercury sees no process where the EA justifies the problems outlined in the current TPM as warranting a “big bang” reform and we believe this has contributed to industry frustration with the TPM process. We suggest the EA should exhaust researching incremental changes before pursuing a “big bang” reform. See our suggest reform options in section 2 of the cover letter.
66. Over what period should we undertake the vSPD modelling?	Mercury does not support the use of vSPD and specifically its reliance on historical offers to compute stylised future benefits. Despite the above we think although there is merit to including only the most recent data, we think doing so discounts the possible effects a dry year may have on the results. And, owing to the long lead time likely for the TPM proposal to be implemented, we think it is prudent to at least include an additional fifth year of data in the modelling, being the 2018/19 year, to see if there are material differences.

67. Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either case, what is the appropriate level of the VPO?	A fixed VPO should be used, this should reasonably match the prevailing average prices at the relevant nodes prior to the investment being made (to the extent this data is available).
68. Do you agree with the approach we have taken to net distributed generation? Do you agree with the application of our netting policy for particular generator(s)? If not, please provide details of particular generator(s) so that we can consider whether to amend our netting arrangements.	We agree with the idea to net distributed generation.
69. Do you consider that the data used in the impacts modelling (in particular, demand and generation volumes) should be adjusted? If so, please provide reasoning/quantitative calculations.	No comment.
70. In addition to the specific questions above, do you have any other comments on the matters covered in Chapter 5 and this appendix H, including in particular: the indicative year-one transmission charges in chapter 5; and the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A)	No comment.