VECTOR SUBMISSION TO ELECTRICITY AUTHORITY

TRANSMISSION PRICING METHODOLOGY 2019 ISSUES PAPER

1 OCTOBER 2019

CREATING A NEW
ENERGY FUTURE

CONTENTS

EXECUTIVE SUMMARY

1. This submission outlines Vector's response to the Electricity Authority's (the Authority's) consultation on its 2019 Issues Paper (the Issues Paper) on the review of the Transmission Pricing Methodology (TPM).

2. Vector has significant concerns with both substantive and process aspects of the proposals set out in the Issues Paper. Our summary positions are set out in the following table, with more detail in the body of the submission.

3. Vector is also a member of other groups who are submitting on the TPM – specifically the Electricity Networks Association (ENA) and the TPM Group. For the avoidance of doubt, this submission sets out Vector's views on the TPM, which may differ in places from the consensus views reflected in other group submissions.

Topic	***Vector view***
Context	• Electricity supply is evolving rapidly to meet a range of challenges, key among them being climate change and the transition to a low-carbon energy system. New technologies such as distributed energy, battery storage and electric vehicles (EVs) are beginning to shape the network of the future. Transmission pricing must enable innovative solutions to these issues at lowest cost to consumers.
Overall view	• The latest TPM proposal is a modest improvement from the 2016 proposal but still has fundamental problems. Vector does not support implementation of the proposal in its current form, as we do not believe it meets the Authority's statutory objective to promote the long-term benefit of consumers. • Indeed, the proposal entails a substantial wealth transfer away from consumers to generators and large industrials, who are already paying less than their fair share of transmission costs under the current regime. We fail to see how such windfall gains can be in consumers' interests. • We strongly disagree with the proposal to allocate residual charges to load only. The rationale given for this approach is that residual charges on generation would largely be passed on to load in any case in the form of higher energy prices. However, the Issues Paper does not provide any robust analysis or

Topic	*Vector view*
	empirical evidence to support this view despite it being fundamental to the Authority's statutory objective.

Substantive concerns

Beneficiary-based charging for historic investments	• As we have highlighted repeatedly in past TPM submissions, introducing beneficiary-based charging for historic grid investments is internationally unprecedented and defies well-accepted economic principles. Reallocating sunk grid costs is inefficient, unfair, and creates significant uncertainty for investors. It is telling that the Cost Benefit Analysis (CBA) in the Issues Paper has not identified any quantifiable benefits from re-allocating historic costs.
Beneficiary-based charging for future investments	• In principle, Vector supports the case for introducing beneficiary-based charging for future investments. However, implementation is likely to pose significant challenges in practice. If beneficiary-based charging for future investments is introduced, grid users must be given rights to scrutinise and, where appropriate, veto investment plans. Otherwise the proposals will do little to improve the efficiency of grid investment.
Removal of the RCPD charge	• We acknowledge that the current Regional Coincident Peak Demand (RCPD) charge is imperfect and can at times lead to volatile prices that are not cost-reflective. However, we do not believe that removing the RCPD charge entirely – without any replacement price signal for grid use at peaks – is the right solution. Such a change would remove a significant lever for incentivising investment in peak shifting technologies such as load control, which in turn reduce the need for costly future grid upgrades. Also, the assumption that locational market prices (LMPs) will provide a sufficient signal of congestion is not plausible given the current market arrangements whereby distributors are the counterparties to Transpower. This is discussed further below.
Allocation of the residual charge	• The Issues Paper does not provide any evidence to support the proposal to levy residual charges solely on load. As we have argued previously, it is incorrect to assume that fixed charges to generators will automatically flow through to load, since generators in a competitive market should dispatch based on marginal costs not fixed costs. It is essential that the models be re-run with

Topic	*Vector view*
	alternative cost allocations, including an 85% generator / 15% split (the inverse of the current allocation). This will allow the full extent of any locational benefits and subsequent consumer and producer surplus effects to be identified. Without doing such modelling we struggle to see how the Authority can show they have robustly considered allocating more to generators as opposed to consumers – a fundamental concern given the Authority's statutory objective to promote consumers' long term interests.
Contractual framework for pass-through of transmission charges to customers	• The Issues Paper does not consider whether the industry contractual structure is fit-for-purpose in relation to transmission charging. In particular, the contractual counterparty for the majority of transmission charges on load is actually distributors, whereas it is retailers and end consumers who are expected to respond to price signals. Distributors would be largely indifferent to transmission charges were it not for the fact that they have been contractually forced to pay for the assets. Furthermore, the Low User Fixed Charge (LFC) regulations restrict distributors' ability to pass through fixed charges to consumers. Advice from the Authority's own staff notes that this undermines the efficiency of the TPM.
Cost-benefit analysis (CBA)	• The CBA remains flawed. As noted above, we are particularly concerned at the lack of any modelling on cost allocation between load and generation. The fact that net benefits from more efficient grid use are only forecast to become positive almost a decade following implementation of the new TPM is also very concerning, given the significant uncertainty over how technology and grid use will evolve. Other comments on the CBA are discussed in the body of the submission.
Process-level concerns	
Alignment with Government policy	• The Government's Electricity Price Review (EPR) expressed significant concerns with the TPM process to date, noting that it had been "costly and contentious". To address its concerns the Panel recommended the introduction of a Government Policy Statement (GPS) to give guidance on appropriate principles for transmission cost allocation. Clearly, the Authority should wait for the Government's response to the Electricity Pricing Review (EPR) before making any further decisions on the TPM.

Topic	*Vector view*
Engagement with prior submissions	• It remains a point of deep frustration to Vector that the Authority has still not adequately engaged with the submissions it has received in the long course of the TPM review, including from renowned international experts. For example, as noted above it has not engaged with the question of cost allocation between generation and load, despite the extensive discussion of this issue in the 2015 expert report prepared for Vector by Compass Lexecon.

INTRODUCTION AND CONTEXT

1. The world of electricity supply is evolving rapidly to address a range of critical challenges – key among them being climate change and the transition to a low-carbon energy system. New technologies such as distributed energy, battery storage, and EVs are beginning to shape the network of the future. Local and central government initiatives (e.g. recent EV support and commitment to de-carbonisation targets) will influence this evolution further.

2. This is relevant both to the way that we operate and invest in our network, and – importantly – to the regulatory settings that influence our and other EDB behaviour. Auckland growth is unprecedented, with infrastructure across the board struggling to keep up. Vector is firmly committed to pursuing innovative solutions to these issues that deliver maximum value to our customers at minimum cost. Transmission pricing must be designed to enable and support the transition to a new energy future.

3. There is significant uncertainty as to how new energy technologies will impact on use of the grid. There are plausible scenarios in which grid use could decline significantly, for example due to a significant increase in local distributed generation and storage. On the other hand, demand for grid-connected electricity could rise in response to greater electrification, particularly of the transport sector.

4. In this context, regulatory settings should be flexible and incremental change should be preferred to sweeping reform. We accept that there is scope for improving the current transmission pricing arrangements, but we are not convinced of the case for radical change. Vector has concerns over both the substance and process aspects of the Authority's latest TPM proposals, which are set out in detail below.

5. Vector's concerns also extend to how the TPM review is themed around the current structure and market framework. It is of concern that there is little or no consideration of demand-side solutions and how these could be promoted for the long-term interests of customers – for example by offering substitutes for generation and transmission through digital technologies. Instead the methods explored seem to largely perpetuate historic current market structures.

6. To inform and support our submission, we commissioned Professor Derek Bunn of London Business School (LBS) to undertake a high-level review of the issues, including relevant comparisons with developments in other jurisdictions. Professor Bunn's report is enclosed as Attachment A.

SUBSTANTIVE CONCERNS

Overall impact on customers

7. As with previous iterations of the TPM review, the 2019 proposals entail a large re-allocation of transmission costs away from generators and large industrial customers to predominantly residential customers. The proposals would see 88% of Transpower's costs loaded onto consumers, compared to the (already unfair) 85.5% under the status quo. Meanwhile, the New Zealand Aluminium Smelter (NZAS) alone would benefit from a reduction in charges of $18m per annum. We fail to see how enabling such windfall gains to large corporates can be in line with the Authority's statutory objective to promote consumers' long-term interests.

8. We note that NZAS, in addition to previously receiving direct government subsidies ($30m in 2013), also benefits from a significant price advantage for its energy price. With NZAS's load equivalent to at least 700,000 households, and a widely reported price of approximately 5 cents per kWh, NZAS already benefits from a $500m-plus implicit subsidy per annum relative to the equivalent price paid for retail electricity by 700,000 New Zealand households.

9. We acknowledge that customers on Vector's network are now projected to face lower price impacts than under the 2016 TPM proposal. Although this would represent an improvement for Auckland customers, a $7m annual increase in transmission charges is not a trivial sum. It will also be of little comfort to other customers who face substantial price shocks – many of whom are in New Zealand's most deprived regions.

10. In any case it is difficult to have confidence in the price forecasts in the Issues Paper, given past experience and the fact that important aspects of the TPM will remain open to change even if the current proposal is implemented. Under the TPM guidelines proposed in the Issues Paper, Transpower will be responsible for the detailed design and calculation of the benefit-based charge, and will be directed to include additional pre-2019 assets within the benefit-based charge if it considers that doing so would better meet the Authority's statutory objective.

Benefit-based charging for historic investments

11. The Authority's proposal to reduce the number of historic investments that will be included in the benefit-based charge from ten to seven is a small step in the right direction (although as noted above, the TPM guidelines do not provide certainty that additional investments will not be subsequently added by Transpower).

12. However, as we have stated repeatedly in past TPM submissions, beneficiary-based charging for historic grid investments runs counter to well-accepted economic principles. Reallocating sunk grid costs is both inefficient and unfair, and does nothing to improve incentives for either grid use or investment. Instead, it creates significant regulatory risk and uncertainty for investors which is likely to raise the cost of capital and undermine confidence in New Zealand's regulatory regime.

13. As noted in Compass Lexecon's 2015 expert report for Vector, recovering historical costs from beneficiaries of the existing assets would not promote efficient decisions on new investments. Moreover, to the extent that the charges vary by location, they could create inefficient location decisions based on the attempt to reduce transmission charges.[1]

14. Similarly, Professor Derek Bunn notes in his attached review of the Authority's proposals that:

> *"For new investments, the beneficiaries pay is efficient because it assumes choice and willingness-to-pay... However, such choice and revealed willingness-to-pay does not apply retrospectively."*

And furthermore:

> *"the apparent anomaly of including 7 legacy investments in the beneficiaries charging is indefensible and undermines confidence in the regulatory regime going forward."*

15. It is telling that the CBA has not identified any quantifiable benefits from re-allocating historic costs. Instead, the Authority relies on the argument that such a move will improve the 'durability' of the regime. Re-allocation of sunk costs, long-argued for by just a couple of corporate entities, has been the most contentious aspect of the TPM review, and a major reason for the lengthy delay in completing the review.

16. We also note that historic grid investments, including the 400kV North Island Grid Upgrade (NIGU) were all approved by the Electricity Commission (EC) on the basis of costs being spread according to the charging methodology in place at that time. Generators who benefited lobbied strongly for the NIGU and other investments to go ahead – yet they do not pay a fair share of transmission charges, and their share is set to reduce under the proposed new TPM. If the Authority insists on reallocating

[1] Pablo T Spiller and Marcelo A Schoeters, *Transmission Pricing in New Zealand: an Analysis of the Electricity Authority's Proposed Options*, 11 August 2015.

sunk costs, allocating a larger portion to generators rather than load would correct past inefficiencies and align cost structures more appropriately between existing and new generators who face benefit-based pricing.

Benefit-based charging for new investments

17. In principle, we recognise that a case can be made for introducing beneficiary-based charging for future grid investments. If they operate as intended, such charges could incentivise more efficient locational decisions by generators and large load customers, and lead to greater scrutiny of grid investment plans by users. In practice, however, implementing beneficiary-based charging will pose significant challenges. As Professor Bunn notes:

> *"beneficiary pays is deceptively engaging and would appear to be uncontroversial as an economic principle. The problem comes when there are many beneficiaries with varying degrees of benefit at varying times of the day and year".*

18. Another concern with beneficiary pays that has been raised by Professor Bunn and others is the treatment of dynamic effects. For example, would charges be recalculated if the forecasted long-term benefits do not materialise? What happens if extra capacity is built in a region to accommodate demand from a large industrial customer who then exits? The Authority has acknowledged that they do not have a solution to such dynamic effects and have not attempted to address them. According to Professor Bunn, *"this is unsatisfactory… dynamic fairness needs further consideration by the EA"*.

19. We acknowledge that there are advantages to providing Transpower with flexibility in designing and implementing the beneficiary charge. However, we are concerned that the draft TPM guidelines provide little clear direction, which makes it difficult to ascertain how the charge will operate in practice. The mechanism for the application of benefit-based charges to generators is particularly important in this regard. The location of generation is always likely to create the largest point source of transmission investment relative to the highly distributed nature of load growth, and hence providing efficient locational signals to generators should be a key goal of beneficiary charging. However the focus of both the current and proposed TPM is predominantly on load. We expand on this point in our discussion of the residual charge below.

20. Regardless of the final design of the charge, if beneficiary-based charging is introduced, grid users must be given rights to scrutinise and, where appropriate, veto

future investment plans. Otherwise the proposals will do little to improve wholesale market competition and the efficiency of grid investment.

Removal of the RCPD charge

21. We acknowledge that the current RCPD charge has flaws. At times it can lead to volatile prices that are not cost-reflective, as the Authority has highlighted in the case of Electricity Ashburton. The RCPD charge provides a strong signal to reduce peak demand across the entire grid, regardless of whether capacity constraints actually exist at particular locations and times. As the Issues Paper states, the RCPD charge can also incentivise inefficient avoidance behaviour which merely redistributes costs between parties without reducing those costs overall.

22. However, we do not agree that removing the RCPD charge entirely – without any replacement price signal for grid use at peaks, such as a Long Run Marginal Cost (LRMC) charge – is the right solution. Such a change would remove a significant lever for incentivising investment in peak shifting technologies such as load control, which in turn reduce the need for costly future grid upgrades.

23. We are also not convinced that nodal prices in the wholesale market are sufficient to signal longer-term transmission capacity constraints, given the variety of factors besides transmission congestion that can impact on nodal prices. Furthermore, the current industry contractual arrangements do not facilitate pass-through of these price signals to retailers and end-customers, since distributors (who are the counterparties to Transpower) do not face the nodal price. This issue is discussed further below.

Structure of the residual charge

24. As in previous iterations of the TPM review, the Authority has proposed to implement a residual charge to recover all costs that are not allocated via benefit-based or connection charges. The Authority's current proposal is that the residual charge should be:

    a. allocated based on historic electricity demand rather than ongoing demand, in order to eliminate any incentives for inefficient avoidance behaviour;

    b. based on non-coincident Anytime Maximum Demand (AMD) as the measure of historic demand, with data collected over at least two years ending prior to 1 July 2019;

    c. allocated on gross load rather than net load;

d. applied to load customers only, and not to generators (except to the extent that they are also load customers).

25. We strongly disagree with the Authority's proposal to allocate residual charges to load only. The rationale given by the Authority for this approach is that residual charges on generation would largely be passed on to load in any case in the form of higher energy prices, since new generators would delay entering until the prices they expected to receive would cover their residual transmission charge. However, the Issues Paper does not provide any empirical evidence to support this view.

26. Compass Lexecon's 2015 expert report for Vector explains clearly why this view is incorrect. Specifically, the residual charge would be a fixed cost for generators that would not be affected by dispatching decisions, which in a competitive market are determined by marginal costs. It is therefore not the case that generators would be able to simply pass through fixed transmission charges to load customers, at least in the short run.

27. Similarly, Professor Bunn notes in his paper that:

> *"On the actual mechanism of **implementing the residual charge**, the case for charging it to load is a weak one… I do not agree with the EA argument, also advanced by Ofgem in GB, that there is no point in charging generators because they would simply pass it on through the wholesale market. If that were credible, then one could argue it makes no difference whichever way and therefore why not split the charges 50-50. But, as the transmission charges would be **fixed, not short-run marginal, costs**, one would not expect those to go through a simple pass though into the energy market. Rather, they would be part of all the annual fixed costs that have to be covered by wholesale market profit contributions*."

28. It is correct that in a dynamic sense charging generators more of the transmission costs will change the required long run average price that they require for entry. This is true for both residual and benefit-based charges as the charges will add to the actual and expected fixed costs a generator would face. Whether 100% of this cost will fall to consumers is a function of competition. It is not clear why the Authority would reduce the ability of competition to determine the actual level of pass through rather than enforcing 100% pass through. From a static perspective the historic decision to limit transmission costs for generators maximised producer surplus at the expense of consumer surplus. The fact that consumers now pay the majority of transmission charges is therefore a logical truism rather than a counterfactual outcome.

29. At a minimum, the revised TPM must not tilt cost recovery further towards load. We would go further however, and challenge the Authority to re-run its models with

alternative cost allocations to estimate the impacts on consumers under different scenarios – including an 85% generator / 15% split (the inverse of the current allocation). This will allow the full extent of any locational benefits and subsequent consumer and producer surplus effects to be identified. Without such modelling it is not possible for the Authority to hold the position that charges will just be passed through to consumers. Nor can it be credible that the statutory objective of long-term interests of consumers has been robustly analysed and considered.

Contractual framework for pass through of transmission charges

30. The Issues Paper does not consider whether the industry contractual structure is fit-for-purpose in relation to transmission charging, and glosses over the question of whether and how price signals will be passed through to the parties who are expected to respond to them – namely generators, retailers and end customers.

31. The Issues Paper largely ignores the fact that the contractual counterparty for the majority of transmission charges are currently distributors. This arrangement exists solely for legacy reasons – it was convenient and of lower risk for Transpower to contract with distributors and leave distributors with the credit and transactional risk rather than contract with retailers. Moreover, the decision to place the majority of charges on distributors (and thereby customers) rather than generators was driven undoubtedly by a desire to protect the value of ECNZ as it was separated by maximising the producer surplus of ECNZ's generation assets.

32. We note that this arrangement differs from that in other jurisdictions. For example, in Great Britain, Transmission Network Use of System (TNUoS) charges are levied directly on retailers based on their half-hourly demand.[2]

33. The Authority briefly touches on the disconnect between transmission and distribution in the Roger Proctor paper, *Nodal Prices and LRMC Charging,* noting at paragraph 100 that if distributors variabilise fixed charges from Transpower, this will undermine the efficiency of the TPM. Vector considers that this potential undermining of the TPM will come about because:

    a. The Low Fixed Charge Tariff Options for Domestic Consumers Regulations (LFC regulations) restrict distributors' ability to charge fixed charges to consumers;

[2] See https://www.nationalgrideso.com/document/114041/download.

b. A significant portion of the transmission charges faced by distributors are not for assets that they are directly interested in (connection assets) but are for assets that are much more integral to LMP prices, i.e. the interconnection assets.

34. Distributors are of course interested in appropriately sized and priced connection assets, and undoubtedly have a vested interest in the capacity of the grid. However, relative to generators and retailers, distributors would have limited interest in the structure of transmission charges were it not for the fact that they have been contractually forced to pay for the assets.

35. The logic that consumers "will pay in the end" is flawed, since the effectiveness of the TPM is contingent on incorrect pass-through assumptions that are not aligned with the contractual arrangements currently in place. As noted above, the Authority has not demonstrated (either empirically or on grounds of economic theory) that its "consumers pay" axiom is correct. Even if consumers ultimately do pay there is no evidence or robust analysis that this shows whether they would pay the same, less or more under the current proposed allocation between generators and consumers. Logically it is hard to see how they would pay more. Vector's concern is there would appear to be little evidence to show that if the allocation was to generators that consumers wouldn't pay less.

36. The Authority's mixed thinking on the incidence of prices and contractual paths is further illustrated at B.224 of the Issues Paper where it states, "This means that effectively load customers would likely end up paying much of the charge whether or not the legal incidence of the charge is on load or generation". As the Authority knows, with the exception of directly connected loads, no load is a legal counterparty to transmission. Additionally, with the exception of directly connected loads, no consumer's counterparty (i.e. no retailer) is a legal counterparty to transmission.

37. Absent reform to the contractual counterparties, Vector may consider shifting its transmission charge recovery to Grid Exit Point (GXP) based pricing, to better align with LMP nodes. However even in this case, it is still unlikely that we could pass transmission charges on as fixed charges.

CBA Methodology

38. We have not commissioned a detailed forensic analysis of the CBA for this submission. Our comments below are based on the information provided in the Authority's report and in the accompanying technical workshop. Our assessment has

also been informed by high-level commentary from Professor Derek Bunn in his attached report, as well as the report from the Lantau Group commissioned by the TPM Group of which Vector is a member.

Assessment of benefits from more efficient grid use

39. Close to 90% of the benefits in the central estimate of the main proposal ($2.6 billion out of a total $2.9 billion) are now estimated to come from more efficient grid use, primarily because of the removal of the RCPD charge. The Issues Paper notes that the 2016 CBA "did not investigate consumer benefits arising from more efficient grid use… because they were considered to be minor". It is implausible that such a large category of benefits could suddenly materialise between 2016 and 2019. The reasons given in the Issues Paper, namely that consumers in the mass-market are expected to "become increasingly exposed to cost-reflective distribution pricing and real-time wholesale prices over time" are not new issues.

40. Our understanding of the modelling is that the majority of the grid use benefits initially arise from increased consumption at peak periods following the removal of the RCPD charge. In later years (2030 onwards) additional benefits result from increased generation investment (in response to higher peak wholesale prices), while costs of inefficient investment in grid scale batteries are avoided. Apparent flaws in this analysis include:

    a. The modelling does not include the costs of additional generation investment arising from the proposal, on the basis that "the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal is assumed to be efficient investment". This makes little sense, given that the benefits of the additional investment *have* been included in the CBA. Furthermore, as Vector highlighted in its submission on the EPR, the assumption that the generation market is competitive and efficient is contradicted by substantial evidence to the contrary[3];

    b. The modelling does not include any estimate of the costs of increased distribution investment resulting from higher peak demand; and

    c. The modelling appears to count wealth transfers from generators to consumers as efficiency (total welfare) benefits, in contradiction to the

[3] For example, see Stephen Poletti (2018), *Market Power in the NZ Wholesale Market 2010-2016.*

Authority's standard practice of ignoring transfers and focusing only on efficiency.

41. We also note that longer term forecasts of prices and investment costs are subject to considerable uncertainty, which increases the further out in time the forecasts are made. It is therefore very concerning that the modelling in the Issues Paper shows negative net benefits with respect to efficient grid use in the initial years following introduction of the new TPM, with positive net benefits only materialising from around 2028 onwards. Indeed, basing the CBA on a forecast of impacts out to 2050 is highly questionable. As Professor Bunn notes:

> *"I am deeply concerned that a CBA for a pricing mechanism change, which will be implemented over a few years, is based upon scenarios to 2050. The EA have made the point that regulatory risk is something the industry should expect. A ten year horizon would be more appropriate. For comparison, the Ofgem Impact Assessment for the removal of triads considered a 12 year horizon. So, to formulate a CBA of this price mechanism change as if were a long term physical infrastructure project is not just inappropriate but makes it look dubiously speculative and over-advocated."*

Assessment of benefits from more efficient grid investment

42. Even if the estimated benefits from more efficient grid use were to materialise, they derive primarily from removal of the RCPD charge. This is a separate issue to the introduction of a benefits-based charge, which has been the centre piece of the TPM reform proposals up until now.

43. The Issues Paper highlights three key benefits related to the introduction of benefit-based charges: more efficient investment decisions by generators and large consumers; more efficient grid investment due to greater scrutiny and less lobbying; and increased certainty for investors.

44. As discussed above, we agree that a well-designed forward-looking benefit-based charge could improve the efficiency of investment decisions by generators and load customers, by internalising the costs of transmission upgrades associated with those investments and encouraging consideration of alternatives to grid investment. It is also possible that a forward-looking charge could lead to greater scrutiny of grid investment proposals by grid users, which could potentially lead to some grid upgrade projects being avoided, scaled back or deferred. For the latter category of benefits to materialise, it is essential that grid users are given a right of veto over new investments.

45. However, as we have discussed at length, reallocating the costs of historic transmission investments will not produce any efficiency gains given that past investment decisions are sunk. The Issues Paper itself acknowledges this, stating that applying the benefit-based charge to historic investments would result in negligible net benefits that are "not significant in the context of the scale of the benefits estimated, and the estimates' range under different assumptions".

46. The suggestion that the TPM proposal would improve investor certainty is difficult to take seriously. The uncertainty around the TPM has largely been a *consequence* of the lengthy review process. The TPM proposals would overturn decisions reached by the EC on the cost allocation of large grid upgrades, so it is difficult to see how investors can have confidence in the regulatory settings going forward.

47. We are also sceptical that the proposal would be more durable and reduce incentives for lobbying behaviour by firms. In fact, given the complexity of the proposed TPM and the fact that major aspects of the design and implementation are being left to Transpower to determine, there is every chance that incentives for lobbying will increase going forward, especially given the continued 100% government ownership of Transpower.

PROCESS-LEVEL CONCERNS

Alignment with Government policy

48. The Government's Electricity Price Review (EPR) expressed significant concerns with the TPM process to date, noting that it had been "costly and contentious". To address its concerns the Panel recommended the introduction of a Government Policy Statement (GPS) to give guidance on appropriate principles for transmission cost allocation.

49. Clearly, the Authority should wait for the Government's response to the EPR before making any further decisions on the TPM. Otherwise, there is a risk that the Authority will put in place a TPM that runs counter to Government objectives for the electricity sector.

Engagement with prior submissions

50. We are frustrated that the Authority has still not adequately engaged with the submissions it has received in the long course of the TPM review, including local and international expert reports. This has been a consistent point of contention with the

industry - that the Authority provides almost no transparency of engagement with the expert views it receives and for which so many submitters have invested in commissioning throughout the TPM process.

51. A key example of this is the impacts of allocating residual charges to load versus generation, discussed extensively above and in our previous submissions. The Issues Paper does not even acknowledge the 2015 Compass Lexecon report commissioned by Vector on this point, let alone engage with the arguments presented. Similarly, the discussion of arguments against removing the HVDC charge comprises only three paragraphs of the Issues Paper and focuses on only one minor argument.

KEY RECOMMENDATIONS

52. In summary, Vector continues to have significant concerns with the proposed TPM. We recommend that the following steps are taken to address these issues:

    a. Drop the proposal to reallocate historic sunk grid assets via the beneficiary charge;

    b. Model the impact of different allocations of residual charges between generation and load, and based on the results of the modelling, allocate these charges in the manner that maximises consumer surplus – in accordance with the Authority's statutory objective to promote the long-term interests of consumers;

    c. Consider whether alternatives to full removal of the RCPD charge would be preferable in terms of maintaining adequate peak signals for investment, including in transmission alternatives such as load control;

    d. Review the industry counterparty arrangements for transmission charging, in particular whether transmission charges on load should be levied directly to retailers rather than via distributors;

    e. Wait for the outcome of the EPR (in particular, the EPR Panel's recommendation to put in place a GPS for transmission pricing) before making any final decisions on TPM.

ATTACHMENT A – EXPERT REPORT FROM DEREK BUNN

See attached report from Professor Derek Bunn, *A Commentary on the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review*.

CONFIDENTIAL DRAFT: Not for Distribution

A Commentary on the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review

By Professor Derek Bunn

September 25, 2019

1. Terms of Reference, Scope and Declaration

This commentary has been prepared at the request of Duncan Mills of Vector Ltd. It represents a personal perspective on the issues raised in the 2019 consultation paper by the Electricity Authority of New Zealand to consider changes in their transmission pricing methodology (TPM). I was asked to provide an independent high level review of the issues and the EA's cost-benefit analysis, with some reference to international comparisons.

In undertaking this review, I have done so in my personal capacity as a consultant. All opinions are my own and do not reflect those of various organisations with which I am affiliated. I have no business associations with any market participants in NZ and no conflicts of interest in undertaking this report as an independent advisor.

2. Expertise

My qualifications for undertaking this review are briefly summarised as follows. I am a Professor at London Business School, with over 40 years' experience in research and advisory work for the electricity sector. I have been Editor of *Journal of Forecasting* since 1984, formerly Editor of *Energy Economics*, and founding Editor of the *Journal of Energy Markets*. Currently, I chair the UK Panel of Technical Experts which advises on resource adequacy and *inter alia* determines the transmission interconnector derating factors, as well as being an independent Panel Member for the Balancing and Settlement Code which controls the British real-time market. I have been a special advisor to the House of Commons Select Committee on Energy and Climate Change, consultant to the UK Competition Commission on Electricity Market Abuse, Expert Advisor to the National Audit Office in their review of the electricity industry reforms, Peer Reviewer for various modeling projects for the government and regulator, and Expert Witness in several litigation cases before the High Court in London and at international arbitration.

3. The issues

The EA proposal refers to the "urgency" (*sic*[1]) in dealing with three current TPM flaws and one emerging TPM challenge. I summarise them in my terms as follows

a) Fairness in charging is indeed under review in many parts of the world. "Beneficiary pays" is deceptively engaging and would appear to be uncontroversial as an economic principle. The problem comes when there are many beneficiaries with varying degrees of benefit at varying times of the day and year. Dealing with legacy cost recovery and forward price signals, through residual charges and beneficiary charging respectively, is also becoming widespread as a principle and less controversial if implemented in a transparent, progressive and nondiscriminatory way.

b) Peak pricing for consumers through RCPD is also under question and is being removed in some jurisdictions as the nature of end-user engagement in the energy market is changing and grid investment become less related to meeting the peak demand, and more to the needs of accommodating new renewable generating resources.

c) Fairness in the HVDC link between the islands may need to be addressed but it could be done as a self-contained problem. It is an example where a kind of beneficiaries pay principle had been applied insofar as the South Island generators were perceived to have been the prime beneficiaries. Current concerns clearly manifest the need for a beneficiaries approach to be adaptive.

d) In addition, the EA intends[1] to offer "long term benefits to consumers" and to "support the energy transition to a low emissions economy at least cost to consumers". Involved in the latter must be the encouragement of efficient self-generation and demand side management by consumers, digitalisation, the use of smart TOU meters and the adoption of electric vehicles, as well as the efficient adoption of grid scale renewable energy resources by the generators and enhanced flexibility solutions by the network operators. How much of this can be invigorated by changing the TPM is open to question.

I discuss the EA's proposals on these issues in turn, except the HVDC link, which I consider needs to be addressed, but does not need a major reform of the widespread TPM to facilitate, as it is already a special case. First, however, I put these in an international context.

4. International Context

Since the 1990s, there have been many parallels in the principles and progression of electricity liberalization in NZ and GB, and especially regarding the regulation of transmission charging. As it happens, there has been a major review by Ofgem of transmission charging, referred to as the Targeted Charging Review (TCR), which is ongoing now concurrently with the EA consultation. This is motivated by similar concerns and shares many principles with the beneficial charging proposals. In explaining the principles which guide their TCR review, Ofgem state[2]:

[1] TPM-2019-Issues-Paper-executive-summary

[2] https://www.ofgem.gov.uk/system/files/docs/2018/11/annex_1_-_tcr_principles.pdf

Throughout the TCR, three principles have guided our work and decision-making. Ofgem has statutory duties which must be adhered to when making decisions of this nature and these principles align with those duties:

a) Reducing harmful distortions; such as inefficient investment in generation for the purposes of reducing residual charges;

b) Fairness; particularly with respect to improving the fairness of residual charges, and primarily for domestic users; and

c) Proportionality and practical considerations; achieving changes in a proportionate and practical manner.

In a similar manner to NZ, there is a distinction between the 'residual' charges that recover sunk costs and contributes to the long-term expenditure required to efficiently maintain and operate the network infrastructure from which all connected users benefit and a 'forward-looking charge' or 'cost-reflective charge' which is designed to encourage efficient use of, and investment in, the network. There is no suggestion in GB that legacy investments will be subject to the forward looking charge.

In particular and of significant interest, Ofgem observe that "Residual charges that are based on measures of network usage incentivise load reduction, reducing the share of the charge paid for by that user, but increasing the share paid by other network users". This has led to a preferred option of fixed charges. They argue that because it is very difficult to avoid a fixed charge without disconnection from the network, this ensures that all users contribute fairly to residual charges. They argued[3] that residual charges levied on generators would ultimately be passed on to demand consumers and so to reduce the potential for distortion and improve competition between different types of generator, network residuals should be charged directly to final demand consumers. Thus, they have taken the decision to set the transmission generator residual charges to zero to remove residuals from generation entirely. Residual charges will be recovered from final demand consumers only, which, Ofgem argues, "will ensure that all generators are competing on as equal a basis as possible". I question this extreme recommendation below. Storage is treated as generation.

Historically, once the total allowed revenue for the transmission company has been agreed with Ofgem, it was charged on a £/kW zonal basis 27% to generators, 73% to retailers, the split being a legacy of privatisation thirty years ago. Demand charges were based upon the three highest demand half hours in winter, called triads, and Generation charges were based upon highest technical export capacity during the year. The rise of behind the meter embedded generation motivated similar concerns of fairness regarding the triads as with the RCPD charging in NZ. They key criticism in

[3] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-update-approach-reviewing-residual-charging-arrangements

GB was that a similar generating unit on either side of the meter should have the same economic value to the system, but peak load demand charging distorts their relative revenues.

Accumulated experience worldwide on the beneficiaries pay approach does not offer many lessons to New Zealand, despite the increasing motivations worldwide in that direction. The term seems to have originated in the US following FERC Order 1000 issued in 2011. In 2016, a FERC[4] report said that, as a consequence of this Order, "It is difficult to assess .. whether the investments made are more efficient or cost-effective". To be clear however, the main focus of that Order was to stimulate non-incumbent investment and improve interregional transmission investments, but it did also initiate the beneficiaries pay approach within transmission regions. Regarding beneficiary charging, the California application is sometimes quoted. At low voltage (<200kv), transmission project costs are recovered from the regional participants involved, whereas projects at higher voltage have cost recovery via a uniform system-wide charge, the argument being that the deeper investments benefit everyone[5]. Noteworthy in the California system is that legacy investments continue to be charged in the pre-existing way whereas new investments will be according to the beneficiary region. Similarly MISO (which covers several midwest States), has sought compliance with Order 1000 by socialising new investment costs for high voltage interstate transmission of mostly new renewable energy sources via a postage stamp rate, arguing that the benefits are widely spread[6]. At the other extreme, Texas chose to stay with a fully socialised transmission charging at all voltage levels, since they could separate from the Order (being electrically isolated). It appears that the lesson from the US is that many States have leaned towards identifying many beneficiaries at least at higher voltage levels, and this has softened the discriminatory edge in the scheme.

Similarly in an international review of residual charging[7], CEPA and TNEI note an increasing move towards, and interest in, capacity rather than volumetric charges (eg Netherlands and Spain). Generally around the world, the rise of prosumers has been the main motivator of network charging reform, essentially at the distribution level but with a spillover to transmission as well. Decker[8] summarises the issue as follows, "*if customer-generators with storage only maintain a connection to the grid as back-up, then a default supplier in an area is faced with a situation of being required to maintain a connection to many customers who consume very little grid-supplied electricity, and, consequently, contribute to only a proportion of fixed network cost recovery. This may be*

[4] https://www.ferc.gov/CalendarFiles/20160317120234-A-4-report-Transmission%20Metrics%20Report_Final.pdf
[5] Federal Energy Regulatory Commission. Order on CAISO Order 1000 Phase 1 Compliance Filing. ER13-103-000. April 18, 2013.
https://www.caiso.com/Documents/Apr18_2013OrderOrder1000Phase1ComplianceFilingER13-103-000.pdf
[6] https://gwujeel.files.wordpress.com/2013/07/miso-ercot-cost-allocation-methods.pdf
[7] https://www.ofgem.gov.uk/system/files/docs/2017/03/cepa_tnei_international_review_of_cost_recovery_issues_final_report.pdf
[8] Decker (2016): 'Regulatory networks in decline', Journal for Regulated Economics, 49, pp. 344-370

exacerbated by the fact that non-default suppliers may refuse to offer contracts to small users of grid-supplied electricity on the basis that they are not profitable."

Thus, by 2019, 42 States in the US have proposed new tariff designs for netmetering which include fixed charges for residential customers[9]. However, implementation has been delicate. For example, in Nevada, whilst netmetering led to significant growth in distributed solar generation and loss of network revenue, attempts to phase in new tariffs met with stakeholder opposition and market exits. As a consequence, there was a policy backtrack and a slower 20yr transition was approved. Grandfathering previous arrangements has also been introduced in California for existing netmetering, but going forward, fixed connection tariffs have been introduced alongside a kWh charge. Although these changes mainly affect the distribution utilities, the experiences do have relevance for TPM changes, particularly grandfathering and slow transitions.

The changes in the Netherlands have received widespread attention. The new capacity based system for transmission in the Netherlands is based on contracted peak capacity and monthly measured peak demand. Reflected also at distribution level, it has slow transitional arrangements. Most notably, the European Distribution System Operators for Smart Grids have become advocates of the Dutch arrangements which they suggest have reduced revenue uncertainty for Distribution System Operators (DSOs). In Spain, a change from a volumetric to capacity base[10] happened in 2014, applied to consumers by voltage level, whilst generators maintained an energy only tariff. The generator tariff is subject to the €0.5/MWh cap imposed by European regulations[11]. Likewise, a two part tariff with capacity components has also recently replaced the energy-only Italian transmission tariffs for HV and EHV customers but not for MV and LV customers.

For NZ the lessons suggest that the move towards residual/beneficiary-pays is happening elsewhere, but with grandfathering and a cautious transitions; that peak pricing like the RCPD is being phased out in some jurisdictions. Other countries are also moving towards capacity based tariffs for transmission and distribution services.

5. Beneficiaries Pay

There are two main controversial aspects here in the EA consultation paper upon which I wish to comment. *The first is about progressing the mechanism of splitting charges into backward-looking residuals and forward looking beneficiaries. The second is about including 7 legacy investments in the beneficiaries pay category*. Stakeholders would expect there to be a clear split at the time of implementation. The most comfortable transition for stakeholders would be to determine that any project with an FID ("Final Investment Decision") before the time of implementation would be

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[9] https://nccleantech.ncsu.edu/2019/07/24/the-50-states-of-solar-42-states-and-d-c-took-action-on-distributed-solar-policy-and-rate-design-during-q2-2019/
[10] https://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_spain.pdf
[11] Regulation (EU) No 838/2010 (Annex Part B)

subject to residual charges. That would respect the economic context within which those investments were planned and financed, consistent with most international practice.

The EA would therefore need a strong argument to apply the **beneficiaries-pay to legacy investments**. The EA has tried to rely upon the economic reasoning that "where users are indifferent about the age of the investment providing a service, charges for the services of old investments will likely be the same as if the investment was new". The word "likely" implies speculation here. The economic argument for treating old and new assets as interchangeable looks at value to consumer and may be hard to ascertain and communicate to all stakeholders.

Furthermore, it is very surprising that the EA is trying to include only a selected few legacy projects in the beneficiaries pricing. This would seem to be opening a Pandora's box for disputes, claims for special treatment and a precedent going forward that the EA is likely to be expedient and discriminatory in its decisions now and in the future. The crucial section explaining why some legacy investments are included in the beneficiaries pay regime is in Appendix D.74 of the EA consultation paper. It says:

> Of course it is possible that past investments were not efficient, either because they were never efficient or because the future turned out to be different from what was forecast at the time of the investment. In principle this could mean there is a difference between the share of benefits that a user actually gets and its share of the cost of the investment. We have allowed for this in our proposal by applying the benefit-based charge only to pre-2019 investments where we estimate the benefit from the investment exceeds its cost.

The EA should have made it clear why "profitability" can justify ex post inclusion of legacy investments into a beneficiaries pay regime. Without further explanation, it appears arbitrary. The EA had previously relied upon an academic economic argument for including all legacy assets, but the reasoning in the above section D.74 is casual by comparison and not persuasive.

My own interpretation of an economic argument for including legacy assets in a beneficiaries-pay regime is that it must rely upon the willingness-to-pay. For new investments, the beneficiaries pay is efficient because it assumes choice and willingness-to-pay. At the very least there will be an open consultation on a new transmission project. And in the new energy transition, it is assumed that there are more choices available including storage, self-generation, community energy schemes, etc, and that is why the EA is advancing these proposals now in the context of decarbonisation.

However, such choice and revealed willingness-to-pay does not apply retrospectively. I presume the EA had this in mind when they stated that they have chosen to apply beneficiaries pay only "to pre-2019 investments where we estimate the benefit from the investment exceeds its cost". This is huge speculation on willingness-to-pay and is not defensible. Furthermore, in theory, all rational transmission investments should have had benefits exceeding costs.

Regulatory risk always exists and market participants know this. It is not necessarily a bad thing, as changes often have to be made. But the implementation of a change which is discriminatory goes beyond the normal careful process of implementing regulatory changes. Thus, one would assume that the EA would have been reluctant to do this and that the reasons for including some legacy investments in the beneficiary analysis would have been fair, transparent and persuasive. However, the EA admits there is not a strong efficiency argument for apportioning beneficiaries to the 7 legacy investments, and that it would be running counter to international advice and practice. Furthermore, it seems disingenuous to rely upon a CBA to imply that this anomaly of including the 7 legacy investments is "not material" (sic). Any CBA on TPM reforms like these will have controversial assumptions. Thus, in a paper sponsored by Transpower[12], Bushnell and Wolak say "… the vast majority of the efficiency benefits claimed by the proposed reforms are speculative and dependent upon strong assumptions. A key feature 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". I agree and would go further to say that dynamic efficiency may be eroded somewhat by an increased regulatory risk premium in investments going forward. My point is that a matter of economic principle and nondiscriminatory fairness should not be confounded with a potentially dubious CBA justification. The EA would be well advised to re-consider this proposal and take the more economically defensible and less contentious route of including those 7 legacy investments in the residual costing.

It is **not trivial to administer** a beneficiaries-pay mechanism, and many implementation details remain. Even if an allocation process is administered transparently and fairly, it implies a contract with a class of customers that could be contestable. What if the proposed long-term benefits do not materialise? Would there be compensation? Do the benefits have to get re-calculated annually as demand, supply and infrastructure changes can alter the relative benefits? What about stranded assets? Suppose a community with large industrial facilities pays for extra network capacity and then the industry exits? The EA do comment on first mover issues in their Guidelines and Policy consultation paper but indicate that they do not have a solution to dynamic effects and will leave the matter unaddressed. **This is unsatisfactory and I would suggest that dynamic fairness needs further consideration by the EA**.

Evidently, the benefits of transmission investment in terms of reliability generally accrue to all users of the system albeit to varying degrees. This, and the above dynamic considerations would suggest that the implementation of beneficiaries pay should not be seeking to identify sharp distinctions upon who does or does not benefit. Rather is should be a nuanced discrimination with an equalization element included.

On the actual mechanism of **implementing the residual charge**, the case for charging it to load is a weak one. International evidence is mixed on this, as indicated above. I do not agree with the EA argument, also advanced by Ofgem in GB, that there is no point in charging generators because they would simply pass it on through the wholesale market. If that were credible, then one could

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[12] James Bushnell and Frank A. Wolak. "Beneficiaries-pay pricing and "market-like" transmission outcomes". February 2017.

argue it makes no difference whichever way it is applied and therefore why not split the charges 50-50. But, as the transmission charges would be **fixed, not short-run marginal, costs**, one would not expect those to go through a simple pass though into the energy market. Rather, they would be part of all the annual fixed costs that have to be covered by wholesale market profit contributions. There is a difference. It would appear most in keeping with the legacy principle of residual charging, insofar as it would recognize past investment considerations, if its allocation between load and consumer does not change substantially from existing practice.

6. Peak Pricing

The memorandum from Bill Hogan to the EA (May 31 on the subject of LRMC) is a useful starting point. It emphasises that transmission investment requirements are becoming **less associated with peak demand periods**. Ofgem also make this point, as do the EA. The argument that scarcity pricing in the energy market, eg through nodal pricing, should provide the incentive for demand-side response by customers is more persuasive. Trying to do some of it through a contrived peak load mechanism, such as the existing **RCPD** in NZ or the triads in GB, would appear to be quite inefficient. In GB, Ofgem has reformed the imbalance prices in the real-time market to reflect scarcity value more markedly, rather than persist with the triad charging for transmission. If new transmission investments are not being driven by the need to meet demand, but rather to connect new generating facilities, eg wind and solar resources, then it is a flawed economic principle to place the charges on to consumers in a few periods of high demand. Evidently the prices so produced would be far in excess of the marginal value of increasing peak demand transmission capacity. And furthermore a process of charging the marginal value of new renewable connections to a few peak demand periods would create highly distorted, economically flawed and contrived price signals.

But, if the system were indeed constrained at peak demand periods such that either demand response or new transmission infrastructure were needed at the margin, then **the peak load pricing theory** would still apply, as originally intended. In some countries, or regions within countries, this may be appropriate. For NZ however, I note from the CBA, that substantial grid use benefits are associated with the removal of the RCPD charge and higher consumption, which would seem to imply that the EA considers that there are no effective peak load constraints of substance that need managing. I think it is an empirical question if there are some regions where RCPD is, or would be, the actual marginal avoided cost of transmission strengthening. If so, it would make sense to retain elements of the scheme in necessary locations for as long as that remains the case. In that respect the EA could give more thought to mechanisms for signaling peak load transmission tightness alongside energy scarcity. In GB there is a dynamic loss of load probability calculation every half hour which can drive a scarcity price in the real-time market. Generally it is zero and has no effect, but if needed it will give a very sharp signal. Perhaps a more modern solution would be to take out RCPD and encourage the transmission company to contract for flexibility services with aggregators of demand-side and other services, to the extent that the regulator can oversee they offer better value than the transmission company strengthening its network. That is what is becoming more common with distribution system operators, as they face new constraints from end-user generation and EV charging. I am not suggesting these are solutions for NZ, but rather, there may be better mechanisms that with more thought and analysis, could replace the flaws in RCPD without losing a potential peak load transmission capacity price signal when needed.

The **CBA** by the EA is mostly driven by consideration of removing the RCPD. I have serious doubts on the CBA which I will mention below, but regardless of the CBA, I believe in principle that RCPD should be phased out, unless there are special circumstances in some regions.

Evidently, **the economic value of the same generating facility to the system should not depend upon whether it is sited before or after the retailer's meter**. I find that to be the most damning reasoning against RCPD. Furthermore, resources spend by the retailers in trying to forecast the peaks and the number of actions taken in anticipation of peak charging periods that did not materialise, is wasteful[13]. Thus I agree with the EA that RCPD distorts and should be phased out. And, there is a logical interaction with the beneficiaries-pay, insofar as the latter should reveal the marginal value of incremental investments.

As far as consideration of the stranding of existing demand-side assets is concerned, this is evidently a sensitive issue that will require a pragmatic solution and a considerate transition. With smart meters, EVs and V2G operations, flexibility requirements from the distribution system operators as well as battery assets increasingly being bundled by sophisticated aggregators, I think there will continue to be increased value in consumer engagement and end-user assets, even without RCPD. When the removal of triad benefits in GB was announced two years ago, there were complaints from embedded generators and much lobbying, but as of now, they have not exited the market, whilst aggregators have become more active.

7. The Cost Benefit Analysis

CBA analyses by their very nature tend to be controversial in their assumptions and speculative in their projections. And that is true in this case. Most concerning in this CBA is the observation that through the projections the net benefits appear to depend most substantially upon what may happen between 2030 and 2050. Power markets change a lot and after a decade, in my experience from over 40 years work in the sector, market circumstances have always been very different from original expectations. That does not mean we should not plan for the future – we have to – but a CBA which relies mostly upon what happens after ten years is not appealing and may not be robust. **I am deeply concerned that a CBA for a pricing mechanism change, which will be implemented over a few years, is based upon scenarios to 2050.** The EA have made the point

[13] In GB, "triad avoidance" has involved purchasing the services of forecasting consultants and industry comments suggest that approx 30 periods are forecast, and thereby initiated DSM, in order to catch the actual three charging periods a year.

that regulatory risk is something the industry should expect. A ten year horizon would be more appropriate. For comparison, the Ofgem Impact Assessment for the removal of triads considered a 12 year horizon[14]. So, **to formulate a CBA of this price mechanism change as if were a long term physical infrastructure project is not just inappropriate but makes it look dubiously speculative and over-advocated**.

In terms of details, I do not think RCPD removal should be the main part of the calculation. I think, as I have argued above, that aspect should be a matter of principle. On the other hand, the beneficiaries pay principle is the most radical, and the CBA is very weak on that aspect. I think that is mainly because the EA have not fully addressed all of the implementation details for how the beneficiaries will be identified, to what beneficial extent and with what dynamics. This is worrying, because whether the scheme works well, or not, will depend upon a lot of practical details. The EA should have put more thought into that, rather than advancing a dubious CBA.

8. Summary

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.

However, the implementation should signal clarity of economic thinking and the application of transparent, fair principles. The residual/beneficiaries split on the basis of legacy cost recovery and forward investment signals is justifiable and in use elsewhere, but the apparent anomaly of including 7 legacy investments in the beneficiaries charging is indefensible and undermines confidence in the regulatory regime going forward.

As for the application of the residual charge on load only, the argument advanced is not persuasive. Generators should carry some of the cost, especially as much of the new investment is about giving them access to customers.

The removal of the RCPD charging is also a timely move, both in principle and alongside similar changes elsewhere. Consideration should to be given however to whether there is still a need for, and how to transition out of, the peak load scarcity signal in the use of the transmission system, in addition to that provided by the energy market. Also the potential for the transmission system operator to contract directly for demand-side flexibility as needed would be a more efficient way to proceed, if there is indeed a requirement to have a demand –side response to the marginal cost of transmission investment.

[14] https://www.ofgem.gov.uk/system/files/docs/2017/06/lcp_frontier_-_slides_from_workshop_21_march_2017.pdf

The CBA approach present a number of questions around assumptions, but most remarkable to me is its long horizon. It is inherently speculative and, for a pricing mechanism change, as distinct from long term physical infrastructure, it should not have been calculated over more than 10 years. It appears to be too highly dependent upon scenarios between 2030 and 2050.

In terms of the reforms being durable and future proof, many considerations remain for the EA to determine. The dynamic fairness of the beneficiaries needs further consideration regarding how it will adapt to changing circumstances over time. And if this means that beneficiary costs change yearly, the industry must be prepared for that.

Will all these changes accelerate progress in the energy transition to a low carbon economy, as stated in the EA's motivating presentation? That is not so obvious. Connecting and operating new renewable generators in new locations may not become cheaper as a consequence of the TPM. As for greater consumer engagement, these are matters for the distribution price regimes upon which the TPM has at most an indirect influence. In their TPM, the EA should however undertake more analysis on how these changes can, in turn, stimulate the retail and distribution business towards facilitating more efficient consumer choices.