Transmission Pricing Review

2019 Issues Paper

A submission to the Electricity Authority

1 October 2019

Trustpower Limited (**Trustpower**) welcomes the opportunity to provide a submission to the Electricity Authority (the **Authority**) on its *2019 issues paper – Transmission pricing review* consultation paper (the **2019 Issues Paper**).

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Summary of Views

1.1.1 Trustpower finds itself at odds with the views of the Authority on the need for, and nature of, transmission pricing (**TPM)** reform.

1.1.2 We are seeking a stable and transparent set of cost allocation rules so we can make appropriate operational, and investment decisions (including refurbishment and retirement) in relation to our generation plant and develop pricing and service plans that appeal to our retail customers.

1.1.3 This stability is provided under the current Electricity Industry Participation Code 2010 (**the Code**) by a requirement that the TPM can only be reviewed by the Authority if there is a material change of circumstances, and by Guideline 19 of the current TPM Guidelines which provides that Transpower must develop transition arrangements when it proposes a revision of the methodology which would lead to large increases or decreases in the current charges.

1.1.4 It is also provided by the ease with which we can understand, predict and communicate transmission prices and their impacts on our wholesale and retail activities under the current methodology.

1.1.5 These features promote competition, reliable supply and the efficient operation of the industry in line with the Authority's statutory objective. However, these features will not be present under the Authority's reform proposal.

1.1.6 We are acutely aware that we are some distance apart from the Authority on TPM reform.

1.1.7 A key factor in our difference of views relates to our understanding of the Authority's role and mandate in relation to TPM.

1.1.8 Trustpower disagrees with the Authority's view that its statutory objective obliges it to pursue sector-wide economic efficiency in the context of transmission pricing and urges it to reconsider the advice of Professor Yarrow on this topic.

1.1.9 We do not think Parliament intended to give the Authority the burden of amending the Code to promote the overall efficiency of the sector and are concerned that if it assumes such a role, investors will face the risks of ongoing Code changes after investments have been made.

1.1.10 We have discussed these views in prior submissions and also raised them with the Electricity Price Review Panel as the Authority's interpretation of its statutory objective has impacts well beyond its current pricing reform initiatives.

1.1.11 As advised previously, we do not agree that the factors identified by the Authority in its 2012 Issues Paper amount to a material change of circumstances. In particular we note that the Authority's identification of an "increase in computing power" as a material change in circumstances seems to be related to its preference for a more granular asset-based beneficiaries pay pricing (**benefits-based pricing**) rather than any flaws with the current methodology.

1.1.12 Legal issues aside, we have also considered the new "contextual factors" which the Authority has identified as relevant to its decision-making about TPM. As we explain in our submission we think these factors are either not new or actually caution against the proposed reform.

1.1.13 Our difference of view on the statutory objective is an important point as we think it has led the Authority to adopt the wrong framework for assessing the current TPM and developing replacement TPM Guidelines.

1.1.14 In particular, we are concerned that the Authority's interpretation has led it to focus too much on theoretical concepts of economic efficiency and not enough on the practicality and implementation risks of its reform proposals. It has also led it away from the direct application of its statutory objective.

1.1.15 A constant theme of the Authority's seven year review of the TPM is that the interconnection charges need be changed to benefits-based pricing as postage stamp pricing gets a "low score" under the Authority's preferred hierarchy of pricing approaches and does not comply with the Authority's preferred pricing principles.

1.1.16 This factor along with concerns about durability have led the Authority to propose fundamental amendments to the tariff structure, method of allocation, and parties to whom transmission costs are allocated.

1.1.17 The main component of the Authority's reform is a proposal to replace the interconnection and HVDC charges with a benefit-based charge and a residual charge. The benefits-based charge is a fixed charge that would apply to seven existing assets and all new assets. The residual charge is also a fixed charge allocated in a manner which will make it difficult for transmission customers to avoid (such as their historic anytime maximum demand).

1.1.18 The Authority's rationale for using a benefits-based charge for the HVDC and selected interconnection assets is that it is likely to be more durable as it complies with its "*pay for what you get*" principle.

1.1.19 The rationale for removing the regional coincident peak-demand (**RCPD**) charge and replacing this with a fixed charge, reflects the Authority's view that nodal prices are all that is required to promote efficiency.

1.1.20 In order to ensure changes of this order of magnitude are durable, particularly given the size of the wealth transfers involved, it is important that the Authority follows sound regulatory practice in its review of the current arrangements and development of an alternative approach. This includes robust problem definition, credible cost benefit analysis (**CBA**) and a thorough analysis of alternative more tractable reform options.

1.1.21 The Authority's rationale for reform appears to draw extensively on a few cherry-picked examples and assumptions about how workably competitive markets operate rather than a more rigorous analytical approach.

1.1.22 It does not consider scenarios where the current TPM works quite well. Its decision-making criteria keeps changing. It has not used CBA as a tool to evaluate different options. This does not augur well for stakeholder acceptance of the proposals, nor for the durability of the reform.

1.1.23 We acknowledge that the Authority has been prepared to amend the design of its preferred benefits-based approach to address feedback from submitters. These amendments have included changes to the number of existing assets subject to the charge and also the introduction of a price cap to mitigate transition effects for a handful of transmission customers.

1.1.24 It has also made amendments which reflect changes in its own problem assessment. These include significant U-turns on the need for variable vs fixed charges, the role of nodal prices and the relative importance of static vs dynamic efficiency.

1.1.25 With the benefit of hindsight, we do not think the adoption of a decision-making and economic framework (**DME Framework**) for the Authority's assessment of the issues with the current TPM has served the Authority very well.

1.1.26 The Authority appears to have implicitly acknowledged the defects in its assessment framework by its progressive elaboration of its intent and adoption of supplementary pricing principles in both 2016 and 2019.

1.1.27 However, we do not think the latest set of pricing principles make any more sense the ones they are designed to supplement. The end result is absolute opaqueness as to what the new TPM will look like when approved and how it will evolve over time. This opaqueness will inevitably impact on the durability of this reform.

1.1.28 We are also struck by the differences between the pricing principles the Authority now proposes to apply in its decision-making about transmission pricing and the pricing principles it developed in 2011 to reflect its statutory objective. These principles directly refer to the role of transmission pricing in promoting competition, ensuring reliability and the efficiency of the industry, while also taking into account practical considerations, transaction costs, the desirability of consistency and certainty, and the need for the TPM to be transparent and durable for stakeholders.

1.1.29 If the Authority believes that pricing principles are required to guide Transpower's development of a TPM, we urge it to go back to the set of principles it developed in 2011 as these principles have a much greater "*line of sight*" between the Authority's statutory objective and transmission pricing.

1.1.30 We are also concerned that the Authority continues to usurp the role of Transpower in developing pricing rules rather than `guidelines. If the Authority wants to have the principal responsibility for the development of the TPM then it must first change the provisions of the Code which give this role to Transpower. To support such a change it would need to explain why it has a better understanding of transmission assets, and transmission customers than Transpower.

1.1.31 In preparing our response to the Authority's latest proposal we asked Dave Smith, from Creative Energy Consulting (**CEC**), to give us an independent view on whether, notwithstanding our views on the statutory objective, the Authority's revised proposal is the best option to promote the overall efficiency of the sector (amongst other matters). His advice is that the work has simply not been done to provide that assurance.

1.1.32 In particular he has noted:

a. It is not possible to be confident that static efficiency will be improved under the Authority's proposal as the static efficiency of nodal prices requires deep participation by the load side and this is clearly not the case at the moment; and

b. The Authority's proposal to ramp up nodal prices to improve dynamic efficiency is also unlikely to work unless there are other significant changes to market design (including the implementation of real time pricing and significant changes to the FTR regime).

1.1.33 Problematically, Dave Smith has advised that he thinks that the proposals are likely to have adverse impacts on reliability:

> *"The response of the load to the removal of the RCPD charge could be quite rapid, so there could be worse reliability in the interim"*[1]

and on competition as the instability and opaqueness of the proposed TPM will favour large established players and mean that:

> *"…small new entrants are the lifeblood of a competitive market due to their ability to disrupt the incumbents. Under the proposed TPM, they could be substantially disadvantaged, possibly to the extent that they do not enter the market at all"*[2]

1.1.34 Dave Smith's advice has led us to conclude that the Authority's proposal is not consistent with its statutory objective (whichever interpretation is adopted).

1.1.35 In our view the Authority's decision-making criteria has led it to reject options (including modified versions of the status quo or the options it initially dismissed) which are not only far more likely to achieve the Authority's various reform objectives, but are also more likely to be more tractable to stakeholders.

[1] CEC 2019 Report, p. 9.
[2] CEC 2019 Report, p. 37.

1.1.36 To be frank we think the Authority's development of multiple different forms of benefits-based options and no other pricing approaches is not credible.

1.1.37 The singular focus on benefits-based charges is problematic as they are unlikely to be workable or practicable; or promote equity or durability; or improve investment decisions. Further we note that material net-benefits arising from benefits-based charges are unproven.

1.1.38 The Authority's proposal involves an exclusive reliance on nodal prices to manage grid congestion, which is unlikely to achieve efficient outcomes until there is a deeper market on the demand side, real time pricing and a greater ability for retailers to hedge transmission risks. Until these things are in place removing the RCPD charge is a risky, if not reckless, experiment. However we do accept that the RCPD signal can be too strong at certain times, including after recent investments, and so needs to be actively managed.

1.1.39 Dave Smith also shares our concerns about the credibility and quality of the Authority's options analysis. He suggests that either a tilted postage stamp (using a heuristic approach to derive the pattern of transmission flows and usage in the market) or a deeper connection charge (which is something of a hybrid between the benefits-based charge and the connection charge) would improve dynamic efficiency much more effectively than the Authority's proposal. He points out the Authority's reasons for rejecting some options simply do not withstand scrutiny.

1.1.40 As with previous proposals, we also asked HoustonKemp to assess the Authority's CBA.

1.1.41 HoustonKemp concluded have advised us that:

> *"… the EA's cost benefit and options analysis does not provide a basis upon which to form a conclusion that its proposal gives rise to net benefits, either in its own right or as compared to alternatives."*[3]

1.1.42 They have explained why the net benefits claimed by the Authority are illusory. This is because 99% of the change in consumer surplus estimated by the Authority is a transfer from generators to consumers. The net benefits to society from the change in prices are no more than $51 million.

1.1.43 Further, the Authority incorrectly assumes that additional generation and distribution costs should not be included in its accounting of costs and benefits, even though its modelling framework suggests that its proposal would give rise to additional generation costs of $1.9 billion and additional distribution costs of $0.29 billion. It follows that, using the Authority's modelling framework, its proposal gives rise to net costs, not net benefits. This is because the costs of additional generation and distribution overwhelm any other benefits that the Authority cites.

1.1.44 HoustonKemp notes that there are a number of errors in the Authority's analysis. These errors include the incorrect representation of the status quo, the estimate of benefits which are conditional on policy, regulatory and technology development that are speculative in nature, and serious modelling errors which lead it to vastly overestimate battery investment under the current TPM and generation entry under its proposal.

1.1.45 HoustonKemp also notes the contradiction between the Authority's analysis of the impact of the inclusion of existing assets and its decision to include them. This occurs because the benefits would increase by $18 million if these assets were excluded. Given the controversy associated with the inclusion of any existing assets, we think the Authority's decision to include them, in the light of its own analysis, is deeply troubling.

1.1.46 As a major component of the Authority's CBA relates to the Authority's proposal to remove the RCPD charge and hence to avoid expected inefficient investment in batteries under the current TPM, and the impact of the increased peak demand on generation investment, we also asked John Culy to examine the Authority's modelling of battery investment.

[3] HoustonKemp 2019 Report, p. ii.

1.1.47 John’s report has confirmed that errors and inappropriate assumptions concerning battery investment and operation have led the Authority to overstate the potential risk of excess “inefficient” battery investment in response to the current RCPD price signal by a factor of around 6x.

1.1.48 He has also advised that, as the Authority’s analysis does not account for the impact of battery charging and discharging by hour, changing the order of net demands within and between its very large load zones, it also substantially overestimates the impact of batteries on the shape of the load duration curve over the peak and shoulder. This overestimate has significant impacts on the Authority’s modelling of wholesale price formation and generation investment.

1.1.49 John has re-modelled battery operation and his analysis shows that although the current high RCPD price may provide too strong a signal for battery investment, this is not a significant efficiency issue for 10 years until battery costs fall significantly.

1.1.50 His advice is that even if this efficiency issue grew over time, then it could easily be addressed by phasing down the strength of the RCPD signal to a lower level over time as and when changes in technology and the market became more certain.

1.1.51 This change can be accommodated under the existing TPM Guidelines.

1.1.52 We would also like to draw the Authority’s attention to the advice the TPM Group has received from Mike Thomas of The Lantau Group (**TLG**). Mike has not been involved in previous consultations on this reform and so he comes to TPM reform with “fresh eyes”.

1.1.53 His report highlights a number of areas where he thinks the Authority’s analysis is incomplete and its solution disproportionate.

1.1.54 He notes that the proposed reform does not provide any guidance on how the various types of benefits are to be treated, such as reliability, safety, competition, option value/development, and other economic benefits, as each has different potential beneficiaries under different conditions and at different points in time. It seems that the Authority intends to count some benefits not others.

1.1.55 He does not agree that this proposal will be durable and notes there is a real risk it will spawn new disputes and arguments over how and where and even when to calculate a cost recovery obligation on various stakeholders.

1.1.56 He also has serious reservations about the adequacy of the Authority’s options analysis. He suggests a more moderate reform proposal would be to apply the proposed benefits-based charge only to assets where it is reasonably straightforward to identify the beneficiaries, such as occurs with a deeper connection charge.

1.1.57 In his view the CBA falls down falls down for a number of reasons including the fact that it fails to identify the potential risks of the Authority’s reform:

> *“… what could possibly go wrong from adopting the proposed changes in their proposed form, rather than a more moderated set of changes more carefully calibrated to minimise inefficient avoidance behaviour while still signalling long-term avoidable transmission costs on average? Quite a few things, in fact:*
>
> - *The loss of an important price signal by removing the RCPD charge and moving to full reliance on LMP for both dynamically efficient grid use and generation investment. Avoidance behaviour might be slowed but also made less economically efficient as there would be a likely loss of valuable information about end user response to price and the viability of various available behind-the-meter options. Cost-shifting is not desirable per se, but observable behaviour and investment has value. Markets thrive on information about choices.*
>
> - *A large shock of short-term wealth transfers due to an insufficient transition, compromising durability;*

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

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

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

There is no fully unavoidable charge in practice, and so shifting the charge around through varying means (short of doing so randomly each year) will still create incentives for some form of avoidance behaviour based on expectations. Yet these will likely be less well informed than expectations based on a modest but reviewable and reasonably aligned long-term average signal. At least with a modest continuing RCPD type charge, any avoidance behaviour that still occurs aligns with long-term capital rationing at a value no higher than the long-term average cost of transmission expansion."[4]

1.1.58 This suggests a staged approach would be better than the Authority's proposal and would have fewer adverse impacts on consumers as most of the benefits of the Authority's proposal are in the out-years. Our submission proposes variations to the Authority's proposal which would include:

a. A revised (and weaker) peak charge that applies to net load, with the specifications of measurement and application to be determined by Transpower;

b. A residual charge applied to net load, with the specific details to be determined by Transpower, subject to the dual criteria of being durable while minimising distortions;

c. Incorporation of the HVDC charges into the residual, with a 5-year transition; and

d. A broader transition path to avoid price shocks, which is achieved by the proportion of charges recovered through the peak charge declining to a lower permanent level.

1.1.59 We note that if the Authority determines to proceed with introducing a benefits-based charge (putting aside our serious reservations), this variation could be expanded to include a benefits-based charge for new investments, in those situations where the beneficiaries are easily identifiable.

1.1.60 To be absolutely clear, this is not our preferred option as we think any application of benefit-based methodologies will fail due to the practical difficulties of accurately assessing beneficiaries of transmission assets over their lifetime and the challenges that market participants will have in understanding what charges will apply to them.

1.1.61 We also note that if the Authority published the Proposed TPM Guidelines this will put Transpower in the very difficult position of having to develop a new TPM when there is strong evidence that the Proposed TPM Guidelines:

a. have not been developed under a robust problem definition and options analysis process;

b. are not supported by the results of a credible CBA; and

c. are not consistent with the Authority's statutory objective (whichever interpretation is adopted).

[4] TLG 2019 Report, p. 9.

1.1.62 Transpower will also have to consider if the new TPM Guidelines are lawful to the extent that they constitute detailed rules and not "guidance".

1.1.63 Further, after developing the TPM, either the Authority or Transpower will need to repeat the cost benefit and options analysis to ensure that section 39 is complied with, and in the event that either process establishes that the new TPM Guidelines are not delivering the best method of achieving the Authority's statutory objectives, begin this reform process all over again.

1.1.64 Given the advice of our experts to date, this seems highly likely.

1.1.65 There is also a risk that any assessed beneficiaries of particular transmission assets, who do not agree that the assessment is fair, decide to challenge the lawfulness of this reform.

1.1.66 This could mean that stable transmission pricing is many years away.

1.1.67 This raises the issue of "where to from here?"

1.1.68 Of course we would like the Authority to stop this reform, on the basis that we do not think it has been appropriately justified. However we accept that this is unlikely.

1.1.69 We think that given the impact of differing interpretations of the statutory objective have on the pricing principles that apply to transmission pricing, the Government should be approached to resolve this issue in the form of a Government Policy Statement.

1.1.70 A Government Policy Statement could also provide a useful vehicle for the communication of the Government's wider priorities for our sector including in relation to the distributional impacts of this reform on some of New Zealand's most vulnerable communities and on the additional risks it imposes on the attainment of the Government's climate change objectives.

1.1.71 The Authority should then work directly with Transpower to quantify the size of any shortcomings of the current TPM and to evaluate the other options identified by stakeholders (including our suggestions) to develop a proposal that will better achieve the statutory objective and the criteria in the Government Policy Statement.

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Part I

2 Introduction

2.1 Current consultation

2.1.1 Trustpower thanks the Authority for the opportunity to submit on its 2019 Issues Paper.

2.1.2 The 2019 Issues Paper presents:

a. The outcomes of the Authority's review of the current TPM and current TPM Guidelines against the Authority's updated decision-making criteria (**TPM Review**);

b. A proposal to replace the existing TPM Guidelines with a new set of guidelines (**Proposed TPM Guidelines**); and

c. A process for Transpower to develop, and the Authority to approve, a new TPM which complies with the Proposed TPM Guidelines (**TPM Development Process**).

2.2 Comment on the Authority's consultation process

2.2.1 Our concern with the lack of time the Authority afforded for consultation on the Authority's 2016 Issues Paper led us to seek a judicial review of the Authority process. We were unsuccessful as the High Court considered it could not comment on the adequacy of the process until the process was complete, including the process to develop and consult on the TPM itself.

2.2.2 We therefore particularly appreciate that the Authority has adjusted its consultation approach in relation to its 2019 Issues Paper to provide more time for submissions, hold regional workshops and allow cross-submissions.

2.2.3 However, even with this extra time we found that we were not able to answer all questions. We suspect the Authority has underestimated the time and resources required to respond to its proposal.

2.2.4 Our experience at the workshops we attended was that the Authority regarded these primarily as a forum to explain its proposal rather than to have a two-way dialogue on emerging issues or concerns.

2.2.5 We encourage the Authority to consider holding a public hearing after (or during) the cross-submission period so parties can directly share their views on this proposal with the decision-makers.

2.3 Structure of this submission

2.3.1 This submission has been structured around the following topics:

a. Part I makes some introductory remarks, provides an outline of the Authority's process to date, comments on the legal framework applicable to this reform process, and provides a summary of our views;

b. Part II focuses on the TPM Review and discusses the threshold for change, other relevant context, the Authority's decision-making criteria and the nature of its problem assessment and options evaluation;

c. Part III considers the Proposed TPM Guidelines including the extent to which they will achieve the Authority's regulatory objectives for transmission pricing and comply with the statutory objective. We also provide comments on the Authority's CBA;

d. Part IV considers peak demand charges, the adequacy of nodal prices to address efficiency and examines the extent to which benefit-based charges will in practice meet the Authority's objectives and then presents a variation to the Authority's proposal; and

e. Part V considers the TPM Development Process.

2.3.2 Our answers to the Authority's consultation questions are presented in Appendix A.

2.3.3 Detailed case studies which explore the sensitivity of modelling the beneficiaries of transmission assets are presented in Appendix B, along with more detailed commentary on the approach of using vSPD to model the beneficiaries of the existing seven transmission assets identified by the Authority in Appendix C.

2.4 Expert reports

2.4.1 In developing this submission Trustpower has been guided by a number of expert reports which are attached to, and should be read as part of, this submission.

2.4.2 These reports are presented in Appendix D -G, respectively:

a. HoustonKemp, "*Review of the cost benefit and options analysis of the EA's proposed TPM Guidelines*", September 2019 (**HoustonKemp 2019 Report**);

b. Creative Energy Consulting (**CEC**) Pty Limited, "*Review of TPM Third Issues Paper*", September 2019 (**CEC 2019 Report**);

c. John Culy Consulting, "*Battery Analysis*", October 2019 (**Culy Report**); and

d. The Lantau Group, "*Comments on the Transmission Pricing Methodology*", October 2019 (**TLG 2019 Report**).

2.4.3 We have also relied on the expert reports we commissioned as part of our previous submission on:

a. this TPM process; and

b. the Authority's previous parallel review of the distributed generation pricing principles.

2.4.4 Please note that to facilitate readability we have omitted footnotes and other references within the quotations provided in this report from these experts' reports, as they are easily obtained from the source documents that are referenced.

3 Authority’s process to date in this reform

3.1 Review of the TPM

3.1.1 The Authority began the current tranche of TPM reform in 2011 by removing the pricing principles in the Code which previously applied to transmission pricing.

3.1.2 It then developed a DME Framework to identify the transmission pricing structure which it believed would best promote the overall efficiency of the sector.

3.1.3 This was subsequently supplemented by two new pricing principles (cost-reflective and service-based pricing) in 2016 (**2016 Pricing Principles**) and six further pricing principles in the 2019 Issues Paper (**2019 Pricing Principles**).

3.1.4 In the period from 2012 to 2019, the Authority continued its TPM Review applying the DME Framework and new pricing principles as they were developed.

3.1.5 The final outcome of the Authority’s TPM Review is contained in the 2019 Issues Paper.

a. Chapter 2 provides a summary of the problems which the Authority has found with the current TPM;

b. Appendix D contains an elaboration of the decision-making criteria the Authority used in previous TPM Reviews and also presents the rationale for its adoption of the 2019 Pricing Principles in addition to the DME Framework and 2016 Pricing Principles; and

c. The Proposed TPM Guidelines contain a statement of the policy objectives for each element of the proposed charging structure and a set of design rules in clause 1 for Transpower’s development of the TPM.

3.1.6 Our understanding is that the Authority’s review of the TPM has found that its currently does not promote overall efficiency because it:

a. receives a low score in its ranking of different pricing approaches and does not comply with the Authority’s pricing principles;

b. has a number of shortcomings which may distort the relative costs of and decisions about consuming grid supplied electricity, the merits of investing in distributed energy resources and the location decisions of energy intensive industry or generation; and

c. will not be durable as some customers benefit from the grid without paying their share, while others pay more than their share.

3.1.7 We would be grateful if the Authority could confirm that this is correct and that it has now concluded its TPM Review.

3.2 Development of replacement TPM Guidelines

3.2.1 In parallel with its review of the current TPM, the Authority also been developing proposals to replace the current interconnection and HVDC charges with a benefits-based charge and a residual charge.

3.2.2 The Authority considers a benefits-based pricing approach better aligns with its TPM Review criteria than the status quo or any other pricing approach.

3.2.3 A number of variants of benefits-based charges have been considered by the Authority in its 2012 Issues Paper, Beneficiaries Pay working paper, TPM Options Paper, 2016 Issues Paper, 2017 Supplementary Paper and the 2019 Issues Paper.

3.2.4 The mechanism for implementing the Authority's preferred pricing approach is the removal of the current high level TPM Guidelines and their replacement with a new set of TPM Guidelines which sets out the Authority's preferred transmission charging structure.

3.2.5 Four different sets of TPM Guidelines have now been developed (including the ones in the 2019 Issues Paper).

3.2.6 The Authority provides its assessment of the conformity of its Proposed TPM Guidelines with the statutory objective in Chapter 4 of the 2019 Issues Paper.

4 Legal framework for this reform

4.1 Functions of the Authority and Transpower in relation to TPM

4.1.1 Under the Electricity Industry Participation Act 2010 (**the Act**), the Authority's functions include making the Code, undertaking reviews of the electricity industry and providing guidelines to facilitate market arrangements.

4.1.2 Changes to the Code need to comply with section 39 of the Act.

4.1.3 This section contains requirements for consultation on the drafting of the proposed Code change and on a regulatory statement which sets out the objectives, an evaluation of the Code change's costs and benefits and an evaluation of alternative means of achieving the Code change's objectives.

4.1.4 The TPM is part of the Code. It follows that the process in section 39 must be followed when it is changed.

4.1.5 In addition to the requirements in the Act, there are also specific provisions in the Code which address the process by which a TPM is developed or amended.

4.1.6 Under the Code, Transpower may initiate a review of the TPM at any time and the Authority may initiate a review of the TPM if it thinks there has been a material change of circumstances.

4.1.7 The Authority has assumed that its TPM Review does not need to be constrained by the current TPM Guidelines or the nature of the material changes in circumstances it identifies. There is some ambiguity about this.

4.1.8 The TPM Guidelines are not themselves part of the Code but rather provide a vehicle for the regulator to provide guidance to Transpower on the TPM if it wishes to do so.

4.1.9 The current TPM Guidelines were developed by the Electricity Commission under a process which included consultation and approval by the Minister of Energy.

4.1.10 As part of the establishment of the Authority, provision was made in clause 17.118 for the transition of the TPM Guidelines and TPM development process from the Electricity Commission to the Authority. It is not clear to us if the Authority has the power to replace the current TPM Guidelines without repealing clause 17.118.

4.1.11 The Authority has determined that it is more consistent with the efficient operation of the industry if it consults on its TPM reform objectives, CBA, and evaluation of alternative options before the TPM is developed. We agree.

4.2 Nature of guidelines

4.2.1 The provision in the Code is for the Authority to develop "guidelines", not a prescriptive set of rules.

4.2.2 The Covec Report notes that:

> *"…Parliament decided not to assign statutory responsibility for designing the TPM to the EA. Instead, the EA's statutory role is to issue guidelines to Transpower and assess its proposals. This set-up points to Transpower as the main developer of the TPM for review/contesting/ approval by the EA, in a similar way to the capital investment process where Transpower does much of the analysis but the Commerce Commission has the final say."*[5]

4.2.3 Professor Yarrow has advised that there is a sound economic rationale for the transmission owner (who has the best information about its assets and customers) to make the choice about

[5] Covec, *Review of expert reports on transmission pricing*, February 2017, p.9.

transmission pricing structure rather than the regulator particularly where there is a wide range of suitable pricing structures.

> *"… First, in view of the variety of competitive processes to be found in the world, there is a question as to precisely how prescriptive any guidelines for a transmission pricing methodology should seek to be. The relevant issues for the EA are to do with permissible pricing/charging structures, which determine how a given level of revenue recovery (determined by the Commerce Commission) is translated into payments by transmission system users to Transpower. As previously discussed, regulation in other jurisdictions has often tended to be relatively permissive on this matter, being content to determine the overall level of a regulated company's revenues (which largely determined the average level of charges), leaving it to the regulated company to determine the details, subject only to more general constraints set out in the guidelines, as well, of course, to any general constraints established by competition law and by relevant social norms.*
>
> *As indicated, one reason for this is that the regulated company is, as the service provider, typically closer to its customers than a regulatory authority and generally in a better position to discover and respond to any individual requirements on a more bespoke basis, in the sorts of way that might be expected to be observed in a competitive market. That then leaves issues arising from the monopoly position of the transmission company itself to be addressed, and that matter appears to me to be the principal role of transmission pricing methodology guidelines. Speaking broadly, it should be a matter of establishing bounds for permissible conduct, based on judgments that the things prohibited would clearly be inconsistent with what might be observed in a workably competitive market, not in prescribing a particular pricing/charging structure (which itself would just be another form of monopoly pricing, with the EA acting as the monopolistic, price-determining authority)."*[6]

4.2.4 Thus for both legal and economic reasons we think the TPM Guidelines need to be at a high level and discretionary.

4.3 Relevance of the Authority's statutory objective in this reform

4.3.1 The Code sets out dual obligations for Transpower, in developing a TPM, and the Authority in, developing any TPM Guidelines and approving a TPM, to take into account the Authority's statutory objective.

4.3.2 The Code does not say what happens if Transpower and the Authority reach different views on the application of the statutory objective in the context of transmission pricing.

4.3.3 In paragraphs 4.223 to 4.228 of Chapter 4 of the 2019 Issues Paper the Authority restates its prior views that the TPM should be designed so as to promote overall (economic) efficiency of the electricity industry.

4.3.4 Consequently, its review of the TPM and development of replacement TPM guidelines give primacy to the third limb of section 15: "*ensure the efficient operation of the industry*".

4.4 Trustpower's views on the interpretation of the statutory objective

4.4.1 Trustpower has a longstanding concern about the Authority's interpretation of its statutory objective in the context of transmission pricing and the way its analysis has subsumed three separate limbs of the statutory objective into a single efficiency objective.

4.4.2 We first raised concerns about the Authority's interpretation of its statutory objective in March 2014 where we pointed out that the Code change power and statutory objective refer to the efficient operation of the industry and not the overall efficiency of the industry or efficient investment.

4.4.3 However, we now understand that well before we raised this issue with the Authority, there was a difference of view between the Ministry of Economic Development and the Authority on the

[6] Professor George Yarrow, *Some awkward problems raised by the Electricity Authority's Review of the Transmission Pricing Methodology*, February 2017, p. 7.

correct interpretation of the Authority's statutory objective including whether legal principles or economic rules should decide how Acts are interpreted, and the extent to which the Authority should take into account both efficiency and distribution benefits to consumers when undertaking its functions.

4.4.4 We believe matters advanced to the point where a draft Cabinet paper was prepared which would have amended the statute to take the decision out of the Authority's hands. However, this was not proceeded with by the last Government due to other priorities.

4.4.5 We note that distributional issues appear to be a greater priority for the present Government and that new energy legislation is planned for next year. We are not sure if this will clarify the interpretation of the statutory objective but note this is a possibility.

4.4.6 We again ask the Authority Board to revisit its interpretation of its statutory objective and consider this issue very carefully. This is because we think the Authority has misconstrued the law.

4.4.7 We continue to hold the view that the Authority is not responsible for the "*long term economic efficiency*" of the sector which along with equity concerns seems to be the underlying drivers for this reform.

4.4.8 Our reasons are set out in our submission on the Authority's 2017 Supplementary Paper where we submitted "*section 15 is not ambiguous, has a sound economic foundation, and must be given effect to as Parliament intended*".

4.4.9 As Professor Yarrow has noted:

> *"An "economic efficiency" objective would potentially require a regulator to take account of effects in all economically related activities and, in an industry like electricity, this would be a vast and infeasible task. "*[7]

4.4.10 An economic efficiency objective implies the Authority needs to intervene in the sector whenever it thinks that outcomes occur that fall short of its economic efficiency standard (or are sufficiently inequitable to impact efficiency).

4.4.11 We absolutely do not think that is what Parliament intended.

4.4.12 The Authority's construction of section 15 puts market participants at considerable risk in relation to ex-post subjective efficiency judgments (as recently experienced by those owners of distributed generation who relied on the default terms in the Code for ACOT payments).

4.4.13 It follows that we disagree with the Authority that TPM reform should be primarily targeted at the operational efficiency limb of the statutory objective (as interpreted by the Authority).

4.4.14 Instead we think the limb which is most relevant to the structure and incidence of transmission charges is the competition limb. This is where the long-term value for consumers resides.

4.4.15 As Professor Yarrow notes:

> *"The value of promoting competition derives chiefly from the effectiveness of competition as a discovery process. In a competitive market suppliers are under strong pressures to keep trying to find new and better ways of satisfying customer requirements. If they don't, one of their rivals will likely gain competitive advantage and business will be lost….competition is of potential value to the long term interests of consumers because of the benefits that information discovery will bring."*[8]

4.4.16 Professors Bushnell and Wolak have advised:

[7] Professor George Yarrow, *Some awkward problems raised by the Electricity Authority's Review of the Transmission Pricing Methodology*, February 2017, p. 4.

[8] Professor George Yarrow, *Some awkward problems raised by the Electricity Authority's Review of the Transmission Pricing Methodology*, February 2017, p. 3-4.

> *"Transmission is a means to implementing competitive markets in other parts of the industry, rather than a sector that is ripe for competition itself."*[9]
>
> *"We support an approach that attempts to facilitate a competition in wholesale and retail electricity sales, not in the provision of transmission network services."*[10]

4.4.17 We agree. We note there are already mechanisms in place in the wider regulatory framework to address the prospect that there can be non-wire substitutes for transmission services.

4.5 Application of the statutory objective

4.5.1 The Authority uses its statutory objective to guide its TPM Review.

4.5.2 However, rather than apply the statutory objective directly it has chosen to adopt an economic framework and two sets of pricing principles which collectively are designed to identify the extent to which the different possible charging approaches were "*market like*" and promote "*the overall efficiency of the sector*"

4.5.3 As we have previously submitted this is the point at which the Authority started down the path of making fundamental errors of law.

4.5.4 We think it should have more directly applied the statutory objective. We think if this has had been done the Authority is likely to have reached a different outcome in its TPM Review.

4.5.5 We return to this issue in Chapters 6 - 7 where we examine the evolution of the Authority's decision-making criteria and its impact on the outcomes of the Authority's TPM Review.

4.5.6 The Authority also assesses its new TPM Guidelines against its statutory objective.

4.5.7 In its assessment, the Authority acknowledges that within its overall efficiency objective there is a trade-off between dynamic efficiency (which the Authority believes supports benefits-based charges) and operational efficiency (which the Authority believes supports changing the RCPD charge to a fixed charge to avoid distorting operational decisions).

4.5.8 The other limbs of section 15 are only fleetingly referred to by the Authority (in paragraphs 4.226-4.227). In these paragraphs the Authority expresses the view that there are positive benefits for reliability and competition from its proposal and no significant detriments.

4.5.9 In Chapter 8.3 we discuss the extent to which the Proposed TPM Guidelines do in fact promote competition, ensure reliability and the efficient operation of the industry.

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[9] Professors James Bushnell and Frank Wolak, *Beneficiaries-pay pricing and "market-like" transmission outcomes,* February 2017, p. 6.

[10] Professors James Bushnell and Frank Wolak, *Beneficiaries-pay pricing and "market-like" transmission outcomes,* February 2017, p. 14.

Part II

5 Threshold for a review of the TPM

5.1 Purpose of the material change of circumstances threshold

5.1.1 Under the Code, the Authority has to meet a particular change threshold, namely the identification of a material change of circumstances, before conducting a TPM review.

5.1.2 The purpose of the material change of circumstances test is to limit the frequency of reviews of and changes to the TPM. It is an important safeguard for those investing in long life assets. This is sometimes called "*term assurance*".

5.1.3 On 25 March 2014, in correspondence accompanying our submission on the Authority's Beneficiaries-pay working paper we said:

> *"There needs to be stability in the allocation methodology and a high threshold for change (particularly if the purpose of the allocation methodology is as EA asserts, to promote efficiency investment in the sector). Rule 12.86 is the principal safeguard against frequent TPM changes"*

5.1.4 We retain this view.

5.1.5 Professor Baldwin relevantly commented in 2016:

> *"Frequency of regulatory change is a matter that goes to issues of both substance and process. Thus, when substantive changes are made to regulatory regimes with a high level of frequency, this creates primary regulatory risks and discourages investment. A similar point, however, applies to review processes and secondary risks. Even the most efficient and low cost procedures for effecting regulatory changes can be deployed at excessively short intervals. The result is secondary regulatory risks -where operators constantly fear the costs occasioned by shifts in regulatory regimes. Investment, again, is discouraged. In the Trustpower context it may be asserted that the frequency of changes in the transmission pricing guidelines is itself a source of secondary regulatory risk."*[11]

5.1.6 Professor Baldwin also advised that the relevant timeframes when assessing the frequency of change depends on the timeframes with which investments need to be made and costs recovered.

5.2 Time period when the threshold needs to be assessed

5.2.1 The relevant time to assess whether or not there is a material change of circumstances is at the commencement of the TPM review.

5.2.2 We do not think it is lawful for the Authority to determine a material change of circumstances has occurred after it is already well advanced in its review of the adequacy of the TPM. Nor is it able to supplement its original determination with other contextual factors as it appears to do in the 2019 Issues Paper.

5.2.3 It is not sufficient to say the Authority is "*continuing a process started by the Electricity Commission*[12]" or that the priority of progressing the TPM review was informed by the Chief Executives' forum of which Trustpower was a member[13]. Neither the Electricity Commission nor the Chief Executives' forum appear to have taken advice on the intervention threshold set out in the Code. However, that does not excuse the Authority from compliance with the Code.

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[11] Professor Robert Baldwin, *Regulatory Change Management and the Reasonable Regulator,* July 2016, p. 3.

[12] Refer to the introduction on the Authority's webpage for TPM reform: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

[13] Refer to correspondence between the Authority Chair and Trustpower Chair dated 8 July 2016.

5.2.4 Our view is that the review was not driven by a material change of circumstances but by the Authority's opinion that the TPM could be more market-like.

5.3 Nature of the circumstances identified as material

5.3.1 The factors identified by the Authority in its 2012 Issues Paper, as restated in the 2019 Issues Paper, along with further new factors, either collectively or individually, do not amount to a material change in circumstances.

5.3.2 Our reasons have been set out in previous submissions and so are not repeated here.

5.4 Supplementary relevant circumstances or "contextual factors"

5.4.1 The Authority considers that there are four major changes to the current operating environment which provide important context for these fundamental amendments.

5.4.2 Three of the contextual changes identified by the Authority are interrelated. They include the prospect that:

a. climate change policy will change;

b. new energy technologies will emerge; and

c. Transpower's regulated asset base will substantially increase as it both replaces old assets and invests to meet new demand.

5.4.3 Trustpower agrees these changes to the operating environment are occurring – the electricity industry is always evolving. However, we do not agree that these changes require fundamental TPM reform.

5.4.4 Similar changes and challenges were known at the time the current TPM Guidelines and TPM were developed.

5.4.5 In our submission on the 2016 Issues Paper we set out the events from 2003- 2010 that establish that the Ministry for Economic Development and the Authority's predecessor the Electricity Commission both knew that Transpower was planning a major increase in investment in the transmission grid. It follows that the current TPM Guidelines were developed by the Electricity Commission and approved by the Minister of Energy with a substantial increase in transmission investment in mind.

5.4.6 New energy technology was also a feature of the environment prior to the development of the current TPM. There was also a strong policy interest in environmental efficiency and initiatives to lower emissions. This was reflected in the legislative framework. For example:

a. When the Part 4 regulation of electricity lines companies was developed in 2008, section 54Q was included. This provides:

> *"The [Commerce] Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services."*

b. Similarly, when the current TPM was developed and approved under a set of pricing principles, Pricing Principle 2 required:

> *"The pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options."*

5.4.7 Since the Authority's last proposal to reform the current TPM Guidelines (initially proposed in 2016 and amended in 2017) we have had a change of Government and an Electricity Price Review.

5.4.8 We are surprised that some of the new Government's policy objectives for the energy sector are seen by the Authority as important context for its proposed TPM reform, but other objectives are not, for example energy affordability. We think all the objectives are relevant to the durability of this reform proposal.

5.4.9 We agree that climate change policy is receiving an increased focus from the present Government and that this will result in another evolution for our sector. However, we note that the present Government was elected on 23 September 2017, several years after the current transmission pricing reform process commenced.

5.4.10 The fourth contextual change identified by the Authority is a concern that the uneven sharing in the current TPM, which averages charges for the interconnection assets and allocates the costs of the HVDC link solely to South Island generators, "*will raise questions about whether the pricing methodology is durable*".

5.4.11 The Authority believes that this issue is also inter-related with the need for more future investment in the sector as this investment "*will bring these issues into sharper focus*".

5.4.12 We suggest that another possibility is that these investment needs will amplify the risks of any uncertainty about TPM charges including as a result of extensions to the scope of the charges, disputed benefit assessments, application of price caps and prudent discounts, and the operation of the "reopeners".

5.4.13 The Authority further claims that the recent Electricity Price Review is an example of the consequences of tensions about equity/durability.

5.4.14 Another interpretation is that the recent Electricity Price Review is an example of the consequences of a proposed transmission pricing reform which was developed under a confusing process and resulted in outcomes politicians' thought were either inequitable or poorly justified (or both).

5.5 Relevant contextual factors the Authority has not referred to

5.5.1 The Minister of Energy has recently released a Cabinet Paper titled "*Transitioning to more affordable and renewable energy the energy markets work programme for 2019*". This is a convenient summary of the Government's energy policy objectives.

5.5.2 The Minister says her energy strategy begins with "*a vision for affordable, secure, and sustainable energy system that provides for New Zealanders' wellbeing in a low emissions world*".

5.5.3 It is clear from her vision that affordability, including the impacts of reform on particular groups of energy customers, is a very important priority for the current Government and indeed we would argue Governments around the globe.

5.5.4 Certainly, affordability was a core focus of the recent Electricity Price Review The terms of reference for the Electricity Price Review's Panel of experts required them to consider whether the prices paid for by end consumers are efficient, fair and equitable and noted:

> *"Relevant perspective on fairness and equity include:*
>
> - *Whether all consumers have access to affordable services*
> - *Whether the costs of providing electricity services are or should be socialised or spread evenly across different classes of consumers (eg across households and businesses), or across regions or urban and rural communities."*[14]

5.5.5 Pages 49-52 of the Electricity Price Review Panel's Issues Paper address the process, timing and fairness of the TPM review conducted by the Authority and invited submissions on these matters.

[14] Electricity Price Review, *Terms of Reference,* p.2.

5.5.6 After considering these submissions the Electricity Price Review Panel expressed the preliminary view that a Government Policy Statement would be desirable for transmission pricing:

> *"Such a statement would provide clear guidance on the difficult and contentious issues with which the Electricity Authority is grappling. These include whether or how transmission prices should factor in when and where grid assets are used…*
>
> *….given the costly and contentious debate about transmission pricing methodology discussed in our first report, we think the extent to which transmission, or any other shared national infrastructure, prices should vary between users or regions is best settled with clear guidance from elected governments. A government policy statement is an effective way for the Government to express its policy objectives, in particular whether it is generators or residential and business consumers in poorer regions, such as Northland and King Country, that should benefit from lower charges under the Electricity Authority's proposed transmission pricing methodology."*[15]

5.5.7 At the time of preparing this submission, the Government have yet to respond to this recommendation from the Electricity Price Review Panel but we understand a Government Policy Statement is likely. If issued, a Government Policy Statement, is a matter which the Authority must "*have regard to*" under section 17 of the Act.

5.5.8 In 2011, one of the factors identified by the Authority for reviewing the pricing principles which previously applied to TPM was the withdrawal of the previous GPS on Electricity Governance dated May 2009.

5.5.9 This suggests that if a new Government Policy Statement is issued, the Authority will need to review its transmission pricing principles including those set out in Appendix D of the 2019 Issues Paper.

5.5.10 In the light of this context we think consultation on the Proposed TPM Guidelines at this time is premature and as a consequence inconsistent with the efficient operation of the industry.

[15] Electricity Price Review, *Options Paper*, February 2019, p. 22-23.

6 The Authority's evolving decision-making criteria

6.1 2011 pricing principles

6.1.1 The Authority began the current tranche of TPM reform in 2011 by removing the pricing principles which previously applied to transmission pricing. It considered these principles gave rise to "*duplication and unnecessary regulation*" and an increased risk of judicial review.

6.1.2 As part of this process the Authority considered how it could amend the existing principles in the Code to better align with the Authority's new statutory objective[16].

6.1.3 These revised principles included principles which would:

a. **Promote competition** by allocating costs of transmission services in a way that facilitates or encourages competition in the markets for electricity and electricity-related services taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in those markets.

b. **Promote reliability** by allocating costs of transmission services in a way that encourages market participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total cost whilst being robust to adverse events.

c. **Promote efficient operation** which includes:

   i. where practicable charging the costs of connection to the connecting party (connection charges); and

   ii. where practicable providing locational signalling of long run transmission investment costs, to the extent that these are not already signalled by nodal prices, the regulatory investment test and connection charges; or

   iii. where such locational signals are inefficient or only partially recover the balance of Transpower's economic costs not recovered by connection charges, these residual costs should be recovered in the least distortionary manner.

d. **Be transparent and enduring** in a way that is broadly acceptable to stakeholders.

6.1.4 It also proposed the retention of Clause 12.80 of the Code which provided that in applying the pricing principles, Transpower and the Authority must **take into account practical considerations, transaction costs and the desirability of consistency and certainty**.

6.1.5 We support these principles and think that if they had been applied in the present reform the Authority would have been more likely to come up with a set of TPM Guidelines that were better aligned with its statutory objective and as a consequence would be more broadly supported.

6.2 DME Framework

6.2.1 However the Authority did not follow this path. It decided to remove rather than amend the pricing principles in the Code to reduce the decision-making layers:

> *"While it is true that each application of the statutory objective to a particular decision will give rise to new "evaluation criteria" required to apply the statutory objective, this process becomes much more involved where there are three existing layers (statutory objective, pricing principles and guidelines) and where all these existing criteria have to be internally consistent.*

6.2.2 Its next step was to develop a the DME Framework to identify the transmission pricing structure which it believed would best promote the overall efficiency of the sector.

[16] Option 3 in the Authority's Code Amendment Proposal: Regulatory Framework for Transmission Pricing Proposal: https://www.ea.govt.nz/dmsdocument/9539-consultation-paper-code-amendment-proposal-regulatory-framework-for-transmission-pricing-methodology-tpm which the Authority describes as a "*close adaptation of its statutory objective*".

6.2.3 As we do not agree that section 15 requires the Authority to promote the overall efficiency of the industry, it follows that we think the DME Framework which is designed to identify pricing structures which are expected to yield that outcome will not yield any insights as to whether the current TPM requires reforming.

6.2.4 The Authority has quite simply asked itself the wrong question.

6.2.5 Setting that point aside, we note that a number of experts do not think the DME Framework is very useful or that it has been consistently applied by the Authority.

6.2.6 For example, the Covec Report[17] found that of the ten expert reports which considered the DME Framework: five criticised the framework itself and four criticised its application; and the sole supporter (NZIER) observed that its use had led to markedly different allocation of costs between distributors and directly connected industrials.

6.3 2016 Pricing Principles

6.3.1 Instead of abandoning this framework, the Authority responded to feedback in its 2016 Issues Paper by adopting supplementary decision-making criteria in the form of two new pricing principles: namely the requirements for cost-reflective and service-based pricing.

6.3.2 The Authority said cost-reflective and service-based pricing is required to:

a. provide price signals for efficient use of the grid which might lead to different usage patterns and a different set of decisions before the Commerce Commission in response to those usage patterns;

b. provide incentives for parties to share more information with the Commerce Commission to improve its decision-making on grid investments; and

c. improve durability as parties will be happier to pay for costs of particular assets who are assessed as providing them benefits.

6.3.3 However, as CEC has observed, the 2016 Issues Paper:

> *"… does not explain whether the two pricing principles are intended to be a distillation of the DME framework or to reflect a more fundamental change of thinking."*[18]

and by implicitly equating "*transmission service*" with "*transmission asset*", the Authority has used its pricing principles:

> *"..not just to restate the beneficiary pays principle but to elevate this philosophy above the two other pricing approaches – "exacerbator pays" and "market-like" – that the DME framework considers to be superior.*
>
> *As a result, we see that the beneficiary-pays-based AOB method is proposed as the core pricing method in the proposed TPM whereas the exacerbator-pays-based LRMC method is relegated to "optional" status. Without any justification, the EA has turned its DME hierarchy on its head."*[19]

6.3.4 We were therefore surprised to see in the 2019 Issues Paper that that the Authority considers that its elaboration of its DME framework as presented in the 2016 Issues Paper is robust.[20]

6.4 Relevance of the analogy of workably competitive markets

6.4.1 The rationale for the Authority's continued faith in the DME Framework and the 2016 Pricing Principles derives from its opinion that this decision-making criteria will enable it to replicate the

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[17] Covec, *Review of expert reports on transmission pricing*, February 2017

[18] CEC, *Review of the Electricity Authority's TPM Second Issues Paper*, p. 2

[19] CEC, *Review of the Electricity Authority's TPM Second Issues Paper*, p. 5.

[20] 2019 Issues Paper p190.

outcomes of workably competitive markets. We accept that the construct of workably competitive markets can provide useful guidance to regulators seeking to constrain monopoly behaviours. This, of course, presupposes that the regulator selects comparable workably competitive markets.

6.4.2 In case of the regulation of a monopoly transmission service provider, Professor Yarrow has advised that the relevant workably competitive markets include markets which also have large and lumpy investments, longish investment lags (i.e. significant time lapses between the taking of an investment decision and first service provision in the relevant market), assets with long economic lifetimes and asset specificity.

6.4.3 In these markets' parties will often enter long term contracts where important matters are settled ex-ante while both parties have equal bargaining power. This is an important point, which goes to regulatory stability, and explains why it is unorthodox to apply benefits-based charging to existing assets.

6.4.4 However, beyond this point the workably competitive market verisimilitude may not provide much insight as to the form of TPM which should be adopted. This is because there is a vast range of possible transmission pricing structures which apply in comparable workably competitive markets

6.4.5 This explains why Professor Yarrow focuses on who is best placed to make the decision, rather than which pricing structure should be adopted amongst the range of permissible structures. His report highlights the importance of the transmission owner (who has the best information about its assets and customers) making the decision.

6.4.6 Professors Bushnell and Wolak take a more pragmatic approach to the relevance of workably competitive markets. Their view is that workably competitive markets are a somewhat artificial construct as there is fact no workably competitive market in the case of a monopoly transmission provider.

> *"Throughout the TPM proceeding, a stated objective of the Authority has been to make charges "market-like" and create outcomes resembling competitive markets through its charging structures. The Authority states that "prices in workably competitive markets tend to be service-based, cost-reflective, and readily adaptive," and has pursued its goal of making charges more cost-reflective under the belief that this would make them more market-like. However, the technology of building and operating an electricity transmission network makes it impossible to use a market mechanism to determine cost-effective transmission network investments and set efficient prices for use of the transmission network. …Building and operating an electricity transmission network is generally acknowledged to be a circumstance for which market mechanisms don't work."*[21]

6.4.7 In relation to Professor Yarrow's observations, they comment:

> *"George Yarrow in his comments essentially argues that there are no obvious flaws to the process that led to the current TPM structure, and no obvious reason to change that structure. We agree that the current transmission regime in New Zealand (encompassing short-term pricing, investment planning, and cost recovery) features most of the elements we consider to be an efficient and equitable system."*[22]

6.4.8 In our last submission we noted that the Authority has not produced any evidence for its view that a very granular asset based charging options approximates workably competitive market outcomes. We noted that as far as we could ascertain:

[21] Professors James Bushnell and Frank Wolak, *Beneficiaries-pay pricing and "market-like" transmission outcomes,* February 2017, p. 3.
[22] Professors James Bushnell and Frank Wolak, *Beneficiaries-pay pricing and "market-like" transmission outcomes,* February 2017, p. 2.

> *"…the best evidence available as to how a national transmission company operating in a workability competitive market would seek to price its network is the pricing structure which Transpower adopted when its transmission prices were not regulated. The current TPM largely reflects that pricing structure."*

6.4.9 We still think these points are valid. These factors have led us to conclude that a "claim" by the Authority that its TPM proposal is more "workably competitive market-like" than the current TPM is just that - a "claim". It certainly is not sufficient justification to embark on reform of the type and scale proposed.

6.5 2019 Pricing principles

6.5.1 Notwithstanding its claim that its 2016 decision-making criteria remains robust, the Authority proposes a new set of six pricing principles in the 2019 Issues Paper in addition to the DME Framework and the 2016 Pricing Principles.

6.5.2 These principles are:

> *(a) LMP is generally the best means of restricting the use of the grid to its capacity*
>
> *(b) Each use should pay the cost of connecting to the grid*
>
> *(c) The charges for access to transmission services from a transmission investment should recover the total cost of providing the transmission investment*
>
> *(d) subject to paragraph (e) below, charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment*
>
> *(e) charges for a transmission user should be similar to those for other competing users after adjusting for their size and location; and*
>
> *(f) any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable."*

6.5.3 The CEC 2019 Report notes that there is actually a seventh principle as well, namely the principle that "*you pay for what you get*". The Authority assumes that this principle will ensure the durability of the regime.

6.6 CEC advice on 2019 Pricing Principles

6.6.1 We asked CEC to assess the validity of these principles and the extent to which the Authority has applied them consistently. CEC has advised that the principles are not well founded nor consistently applied.

6.6.2 In relation to the first principle that nodal prices are the best means of restricting the use of capacity to the grid, the CEC 2019 Report states that while this may be a useful aspirational goal it is not a suitable pricing principle as many years of development in market rules and participation would be needed to approach this ideal.

6.6.3 CEC notes that:

> *"… LMP characteristics are likely to change substantially over the medium term due to the factors listed above and potentially other factors not yet identified. Currently, with no nodal scarcity pricing and very limit demand-side participation, it is unlikely that nodal prices live up to the theoretical ideal stated in the EA's principle. Possibly that might be achieved, or be closer to being achieved, in the future. But an effective TPM must reflect the practical realities of today's market."*[23]

[23] CEC 2019 Report, p. 5

and that:

> *"The prospect of nodal prices being best in terms of static efficiency at some point in the future at least seems plausible, if uncertain. The idea that they could also be made to be dynamically efficient is conceptually interesting but practically infeasible. In neither instance does this justify the removal of the RCPD price on the grounds of improving efficiency."*[24]

6.6.4 The Authority's second principle in relation to the allocation of connection costs reflects the status quo and is not contentious.

6.6.5 The Authority's third and fourth principles provides that transmission access charges need to reflect the costs of particular transmission investment and the allocation of these charges needs to be benefits-based.

6.6.6 CEC does not agree that these are appropriate transmission pricing principles.

6.6.7 The CEC 2019 Report describes the two critical flaws which apply to the Authority's preferred benefits-based charging. These are:

a. the reliance on a user to be able to forecast future benefits-based charges including likely future transmission investments, allocation of those benefits and the portion of charges it will face; and

b. the fact that the price signals will not be equivalent to, but rather substantially below, long run costs.

6.6.8 CEC suggests that either a tilted postage stamp (using a heuristic approach to derive the pattern of transmission flows and usage in the market name) or a deeper connection charge (which is something of a hybrid between the asset-based beneficiaries pay charge and the connection charge) would improve dynamic efficiency much more effectively than a benefits-based charge.

6.6.9 The CEC 2019 Report also comments that:

> *"The philosophy that the TPM should be designed with a view to improving the transmission planning process is an idiosyncratic position held by the EA that does not have much support in overseas markets. Whilst the US does employ BP methods, these are used for allocating the costs of investment between transmission companies, a usage that has no relevance to NZ. As far as I know, the US does not use BP methods in the context in which the EA is proposing to use them: allocation of costs between the customers of a transmission company.*
>
> *The US context has shown BP charging to be complex and contentious, particularly in the choice of method and assumptions. But applying it to transmission pricing would raise new challenges which the US has not had to face: whether and how to apply BP charges to new customers who were not present or anticipated at the time that the investment decision was made. Charging new customers is an anachronistic anomaly under the EA philosophy, because those customers cannot possibly influence a historical decision. But not charging them creates discrimination between old and new customers that is unlikely to be justifiable or sustainable."*[25]

6.6.10 In relation to the Authority's fifth principle, the CEC 2019 Report notes that although the Authority advocates a principle of non-discrimination, its proposed TPM is actually riddled with discrimination. For example:

> *".Firstly, the appliance-level price discrimination employed in the design of the residual charge, whereby consumption that has an elastic response will be priced differently to that with an inelastic response.*
>
> *Secondly, the arbitrary division of existing transmission assets into those whose costs are recovered through BP charges and those recovered through the residual charge".*[26]

[24] CEC 2019 Report, p. 9.
[25] CEC 2019 Report, p. 34.
[26] CEC 2019 Report, p. 35.

6.6.11 In relation to Authority's sixth principle, that the residual charge should be designed to distort behaviour as little as practicable, the report advises that

> *"In contrast to the challenge of creating dynamically efficient pricing signals, the problem of residual charging is straightforward and generic. The same problem is faced by transmission owners and regulators around the world, because the fundamental economics of transmission mean that efficient prices alone will not recover the necessary revenue.*
>
> *Rather than learn from overseas best-practice – and even best-practice in NZ – the EA has developed its own unique ideas. These fail to apply the standard Ramsey principles, and instead rely on retrospectivity and price discrimination to minimise user response to residual charges."*[27]

6.6.12 The CEC 2019 Report also addresses the Authority's "*pay for what you get principle*".

6.6.13 CEC's expert view is that for a pricing regime to be durable three conditions need to apply:

a. it needs to be intuitively reasonable;

b. there needs to be a clear trajectory given the expected future; and

c. it also needs to have sufficient flexibility and adaptability to remain intuitively reasonable even when the future differs from what is expected.

6.6.14 CEC consider that the Authority proposal has none of these characteristics.

6.6.15 Based on this advice we do not support these new principles and suggest the Authority abandon them.

6.7 Impact of evolving decision-making criteria

6.7.1 We find it very difficult to reconcile the Authority's rationale for removing the pricing principles in 2011 with:

a. the creation The DME Framework in 2012;

b. the addition of two new pricing principles in 2016;

c. the addition of six further express pricing principles to evaluate the TPM in 2019; and

d. the addition of an implicit principle relating to durability

6.7.2 This evolving decision-making criteria creates the impression that the Authority is changing its criteria retrospectively to suit and justify its preferred methodology.

6.7.3 This perception is strengthened by the fact that some of the principles have not been applied consistently as CEC has illustrated in its various expert reports.

6.7.4 Further, the Authority's decision to add rather than replace decision-making criteria (and the inconsistencies in how all the various principles are applied) means that it is very difficult to understand how future decisions about transmission pricing will be made.

6.7.5 This is not consistent with the Authority's statutory objective and will not result in the desired durability of the TPM.

[27] CEC 2019 Report, p. ii-iii

7 Comments on the Authority's problem assessment and options analysis

7.1 Impact of DME framework and pricing principles

7.1.1 The lack of stable and sound decision-making criteria has had an adverse flow on effect to the Authority's problem assessment and options evaluation.

7.1.2 Transpower, in its submission on the 2014 Beneficiaries-Pays Working Paper, warned of this risk:

> *"A potential issue with application of the DM&E framework is that it divorces identification of problem from determination of solution. This may be reflected in the difficulties the EA has had in establishing a problem with the status quo and ensuring its proposals are commensurate with and proportionate to the identified problem. It appears that the Authority has formed the view that beneficiaries-pay may be the best option, not because it addresses specific problems with the status quo but, rather, because the Authority has formed the view that higher ranked approaches under the DM&E have only limited practical applicability."* [28]

7.1.3 We think this insight applies equally to the various new pricing principles.

7.2 The Authority's approach to problem assessment

7.2.1 The following table sets out our understanding of the course of the Authority's thinking about the problems with the current TPM.

	Problem statement/regulatory objective	Solution	Does the solution work?	Are there other alternatives?
2012 Proposal	**Current TPM is at the bottom of the ladder of administrative approaches in the Authority's DME framework** (which identifies the pricing structures which best promote overall economic efficiency)	**Move up the ladder to another administrative approach** i.e. asset-based beneficiaries pay	**Yes, it is higher on the ladder** – Also has some desirable characteristics such as flexibility of the SPD charge and price signals through RCPD/RCPI allocation of the residual charge Efficiency dictates that 64 existing assets (including the HVDC assets) be included in the charge.	No, other than different variants of asset-based beneficiary pays.
2016-7 Proposal	**Current TPM is at the bottom of the ladder of administrative approaches in the Authority's DME framework** **AND does not meet the new pricing principle of cost reflective service based pricing** (which we define as meaning that the costs of a particular transmission asset need to be allocated to the assessed beneficiaries of the asset)	**Move up the ladder to another administrative approach** i.e. asset-based beneficiaries pay	**Yes it is higher on the ladder**- Also has some desirable characteristics as the AOB is a fixed charge so will not interfere with nodal prices but will send an important shadow price to improve dynamic efficiency. The residual charge will also be fixed so as to remove the inefficient price signals associated with RCPD and improve efficient grid use. Efficiency dictates that 11 existing assets (including the HVDC assets) be included in the charge	No, other than different variants of asset-based beneficiary pays.

[28] Transpower submission on Beneficiaries Pay working paper, at page 9.

2019 Proposal	**Current TPM is at the bottom of the ladder of administrative approaches in the Authority's DME framework** **AND does not meet the cost reflective service based pricing principle** **AND does not meet the six new transmission pricing principles** **AND does not meet the "pay for what you get" principle**	**Move up the ladder to another administrative approach** i.e. beneficiaries pay	**Yes it is higher on the ladder-** Will have the same benefits as our 2016 proposal although we now think the removal of the RCPD charge is the most substantial benefit of the reform. Our CBA provides net costs of including at seven existing assets (including the HVDC assets) in the charge but we have included them anyway as this is a relatively small number and inclusion will enhance durability.	No, other than the optional elements identified for our preferred asset-based beneficiary pays.

7.2.2 The table shows that the Authority's approach has led it to some surprising U turns on what it considers to be the desirable characteristics of a TPM.

7.2.3 For example, we were surprised to see such a strong emphasis on the inefficiencies associated with the RCPD charge in the 2019 Issues Paper as this charge was an integral part of the Authority's preferred reform in 2012, where the Authority stated:

> *"We also believe that the RCPD charge is a positive feature of the proposal as it provides a stable long term signal that investment to avoid peak demand will reduce the costs of network build over time".*

7.2.4 We suspect the Authority's revised view derives from its opinion that nodal prices will be effective at minimising investment in the grid to meet peak demand and its calculation of the benefits that might be available if this charge is removed. However, this is unlikely in the medium term for the reasons discussed in Chapter 11.

7.2.5 We were also surprised that the claim that the current TPM provides poor incentives to scrutinise grid investment proposals now appears to be relegated to a fifth priority. Previously we thought that this was the primary driver for the Authority's TPM reform and the principal source of its claimed benefits.

7.2.6 We think these U turns have occurred because the Authority has started with a theoretical concept of efficiency and then tried to assess problematic features of the current TPM vs the desirable characteristics of its preferred approach rather than starting with specific (quantified) issues with the current TPM in meeting its statutory objective

7.3 Nature of options evaluation

7.3.1 The Authority's early determination that a benefits-based pricing approach should be adopted has also adversely impacted its options evaluation as it has led it to consider multiple variants of this pricing option but no other pricing approach.

7.3.2 It is not credible that there could be no other options (including variants of the status quo or options which scored higher in its DME Framework) worthy of closer examination.

7.3.3 TLG 2019 Report also comments on the inadequate nature of the Authority's options analysis. Its report states that the Authority's CBA is not nuanced enough to assist in differentiating amongst alternative solutions and comments that:

> *"Now, consider that the CBA principally focussed on a BAU scenario in which the existing RCPD charge during peak hours is far higher than any reasonable estimate of avoidable long-run cost of transmission and behind-the-meter alternatives. Accordingly, even before commencing the analysis we know that compared to a similar scenario with just the RCPD charge smoothed out and greatly reduced at peak, the BAU case will be inferior. Like the car analogy, however, we know this even before we start the analysis. Accordingly, the analysis cannot add nearly as much to our understanding of the problem or the nature of potential solutions as we need to know. The*

analysis merely reinforces recognition that something that is already flawed will probably produce an inferior result to something that does not have that same flaw.

It is generally not good analytical practice to jump from a BAU case that starts with a clear economic flaw to an extreme case at the other end of the spectrum unless the point is simply to hammer home a high-level headline message. There is a middle ground of prudent and attractive and relevant options that offer solutions that involve similar benefits and less risk associated with implementing a first-of-a-kind approach in a small, volatile market. The decision variables for choosing amongst these options, however, are not part of the CBA."[29]

7.4 Comments on the five problem statements

7.4.1 Chapter 2 of the 2019 Issues Paper sets out the five problem statements that most concern the Authority. The first three relate to the RCPD charge (distorting use and investment decisions), the fourth is a concern about the impact of HVDC on competition in the generation market and the fifth is the Authority's long held concern about the nature of the incentives to scrutinise grid investment proposals.

Problems with the RCPD charge

7.4.2 We assume that the emphasis placed on the RCPD charge in the 2019 Issues Paper derives from the Authority's CBA where the vast majority of benefits come from more efficient grid use and more efficient investment in batteries.

7.4.3 However, as we explain in Chapter 9, the Authority has overstated the benefits of this reform by a considerable margin. This suggests that the need for this reform may not be as pressing as the Authority assumes, particularly when due regard is had to the benefits and flexibility of the current RCPD charge which appear to be missing from the Authority's analysis.

7.4.4 TLG 2019 Report sides with the Authority's 2012 view and explains that the RCPD charge provides a useful simple signal to elicit valuable information about behind the meter demand elasticity.

7.4.5 TLG suggests that this signal should be recalibrated rather than entirely removed. This can (and has) been done under the current TPM Guidelines suggesting that a weak case for change to the RCPD has been made.

7.4.6 This is particularly true when you also factor in the costs and risks of adverse impacts on reliability of removal of the charge. These risks include the inability to change distribution pricing until the Low Fixed Charge regulations are rescinded, which is entirely outside of the Authority's control.

Problems with the HVDC charge

7.4.7 The impacts of the HVDC charge on competition on the South Island generation are well known and have been identified for more than a decade.

7.4.8 However, what has been missing in the analysis is an opinion from the Authority on whether it thinks the issue is material enough to warrant reform. This is the issue on which its advisory group had divided views in 2011.

7.4.9 Paragraph 2.48 of the 2019 Issues Paper suggests that the Authority has now decided reform is required as it states "*the HVDC charge appears to be large enough to affect investment decisions*."

7.4.10 This could be addressed by allocation to all generators, as has been previously advocated.

7.4.11 However, the Authority does not favour this option over a benefits-based allocation as it does not conform with its "*what you pay is what you get"* principle. This then puts the HVDC charge into the same "camp" as all the other asset reallocations, whereby reallocation needs to be justified primarily on efficiency grounds.

[29] TLG 2019 Report, p. 4.

7.4.12 TLG 2019 Report notes that the HVDC charge has a unique and contentious history and as such could justify a bespoke allocation, guided by an "overarching principle of simplicity".

7.4.13 However, these views will need to be weighed up against the risks noted by Professors Bushnell and Wolak relating to the rewarding of lobbying behaviour.

7.4.14 In short, a judgment call is required (just as it was in 2011).

Weak incentives to scrutinise grid investment

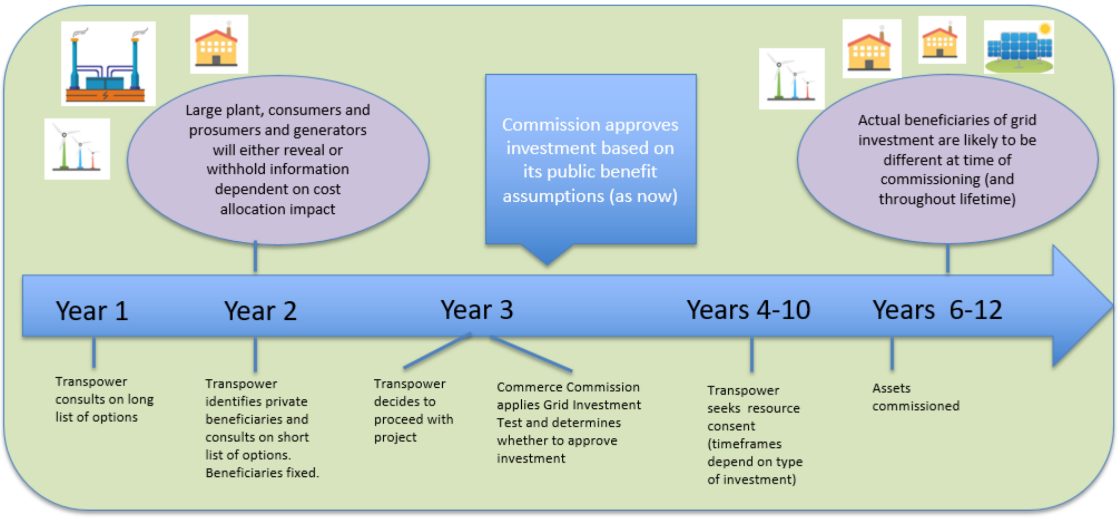
7.4.15 It is unclear that benefits-based charging will improve the information available to the Commerce Commission in the grid investment process and instead may create risks needed investments are impeded.

7.4.16 We share the views of the experts that there may not be any more information about the advantages and disadvantages of particular transmission investments under the new charges than occurs under the current TPM.

7.4.17 We note that the different timescales in which relevant decisions relating to a new transmission investment are made mean it's unlikely that the Authority's anticipated improvements in dynamic efficiency will eventuate.

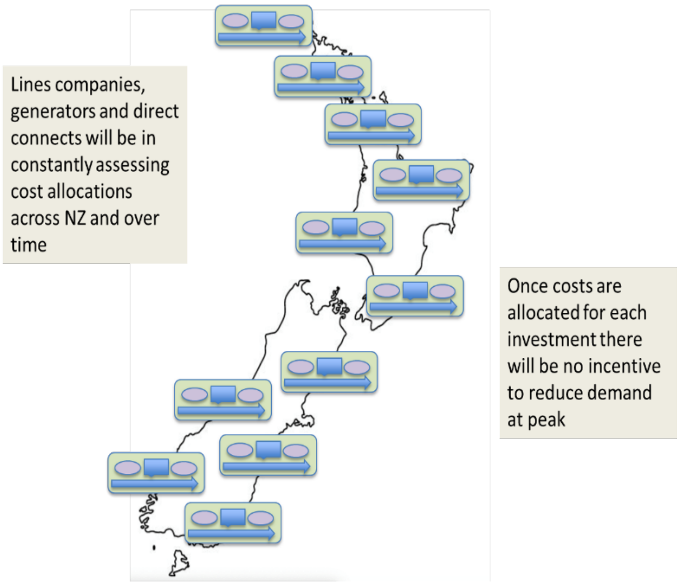
7.4.18 A simple timeline (as depicted below) for development of a transmission asset shows that beneficiaries will need to be identified by Transpower very early in the process (relative to an assets commissioning)[30].

7.4.19 This creates the initial risk of misalignment between identified and actual beneficiaries even before commissioning.



The risk then continues throughout the 30-50 years of the relevant asset's lifecycle:

[30] We note the Authority's clarification that beneficiaries will be locked down at the time of the GIT being undertaken or at commissioning.



7.5 Reliance on hypothetical examples is problematic

7.5.1 In previous submissions, we have commented on the lack of evidence supporting the problem definition, and the subjectivity involved in the selection of hypothetical examples to illustrate problems with the current TPM.

7.5.2 The TLG 2019 Report raises this concern with respect to the assessment of a beneficiary pays approach, recognising the focus on "*comparatively extreme examples where significant beneficiaries appear to exist*"[31].

7.5.3 Moreover, the CEC 2019 Report provides an example of how this subjectivity has led the Authority to prefer beneficiaries pay approaches over other options.

> *"The BP approach can be effective and efficient in a limited number of situations where the entry of a new generator or large load is likely to prompt immediate and nearby "shallow" transmission investment. In arguing the case for BP charges, the Issues Paper always refers to such situations.*
>
> *But the more general and typical situation, accounting for the majority of historical and future transmission costs, is "deep" investment on major transmission routes to accommodate general growth in transmission flows, being the aggregate effect of myriad investment decisions taken by smaller parties. BP does not promote efficiency in such decision making, due to problems of dilution and opacity. Dilution, because the pricing signal provided by BP charges in this situation is likely to be a fraction of the long-run transmission cost. Opacity, because it will be impossible for most parties to predict these future BP charges in any case."*[32]

7.5.4 CEC notes that there are several possible alternative TPM options that overcome these difficulties of "opacity" and "dilution" which apply to benefits-based pricing.

7.5.5 CEC recommends a tilted postage stamp option that uses a *heuristic* approach: a simpler method that, empirically, is expected to give similar pricing outcomes to long run nodal prices. CEC says:

> *"Nodal prices are generally higher in importing regions and lower in exporting regions, so the long-run nodal pricing approach would lead to prices that "tilt" upward from south to north, reflecting the generation direction of transmission flows and congestion. Similarly, since the allocation of benefits from transmission investment will reflect the removal of this congestion, the long-run BP prices will have a similar-style tilt. So, the heuristic method will involve tilting prices in the direction of transmission flows and can reasonably be called a Tilted Postage Stamp (TPS) to reflect the history of such concepts.*

[31] TLG 2019 Report, p. 21.
[32] CEC 2019 Report, p. 21.

Reflecting its more complex antecedents – long-run nodal pricing and long-run BP charging - the TPS prices would also have the general characteristics of:

- *Applying to peak load or output; and*
- *Applying equally and oppositely to load and generation in the same location*

The TPS concept has been around a long time and, in my view, is not going to go away. This is because all plausible transmission pricing methodologies are likely to demonstrate these characteristics over the long term if appropriately designed. If there are two ways to get to the same destination – an easy way and a hard way – the easy way will always be preferable."[33]

7.5.6 CEC also says that a deep connection charge would be more effective than a benefits-based charge for the scenario of a new generator or load prompting investment in *shallow* transmission to remove the *local* congestion that it would create.

> *"…this "shallow investment" issue could instead be addressed by extending the existing connection charging regime to incorporate deep connection charges. Connection charges apply only to dedicated assets: those used only by the connecting user. A deep connection charge would extend this to network assets used only by a few, local users, of the sort envisaged in the EA's examples.*
>
> *A deep connection charge would be similar to a BP charge in that the costs of the shallow asset would be shared between local users in proportion to the attributable benefits. However, unlike the BP charge (but similar to a connection charge), it is a one-off charge that is applied when a new user connects. So, it is something of a hybrid between the BP charge and the connection charge "*[34]

7.5.7 However, neither of these options have been properly evaluated by the Authority.

7.6 Conclusion on problem definition and options evaluation

7.6.1 In our view the lack of a disciplined approach to problem definition and options evaluation has meant the Authority has

a. failed to take into account the benefits of the status quo and/or the weaknesses of its preferred option; and

b. prematurely dismissed reform options would be more proportionate, carry lower cost and risk, and better promote the statutory objective.

7.6.2 What is urgently required to resolve this reform is a disciplined evaluation of the problems with the current TPM and of the ability of the most practicable options to address those problems.

7.6.3 Based on recent advice, we think those options are:

a. The status quo;

b. The status quo with modifications to facilitate the further management of the strength of the RCPD and to enable a wider allocation of the HVDC charge;

c. The Authority's proposal (ideally with the modifications described in Chapter 13);

d. Tilted postage stamp as described in the CEC 2019 Report; and

e. Deeper connection charges as described in the CEC 2019 Report and TLG 2019 Report.

7.6.4 A robust CBA needs to guide this assessment in accordance with well-established best practice as recommended by TLG.

[33] CEC 2019 Report, p. 18.
[34] CEC 2019 Report, p. 19.

Part III

8 The Authority's proposal

8.1 Core features of the Authority's proposal

8.1.1 The Proposed TPM Guidelines in the 2019 Issues Paper comprise of two parts:

a. The core proposal – under which the costs of all new transmission assets from 2019 onwards and selected existing pre-2019 transmission assets will be allocated to those parties who are assessed at a single point of time (either during the investment approval process or following commissioning) to be the *lifetime beneficiaries* of the relevant assets (the benefit-based charge).

   The balance of Transpower's regulated revenues would be recovered solely from load by a second fixed charge (the residual charge) on the basis of an approved allocator such as historic anytime maximum demand; and

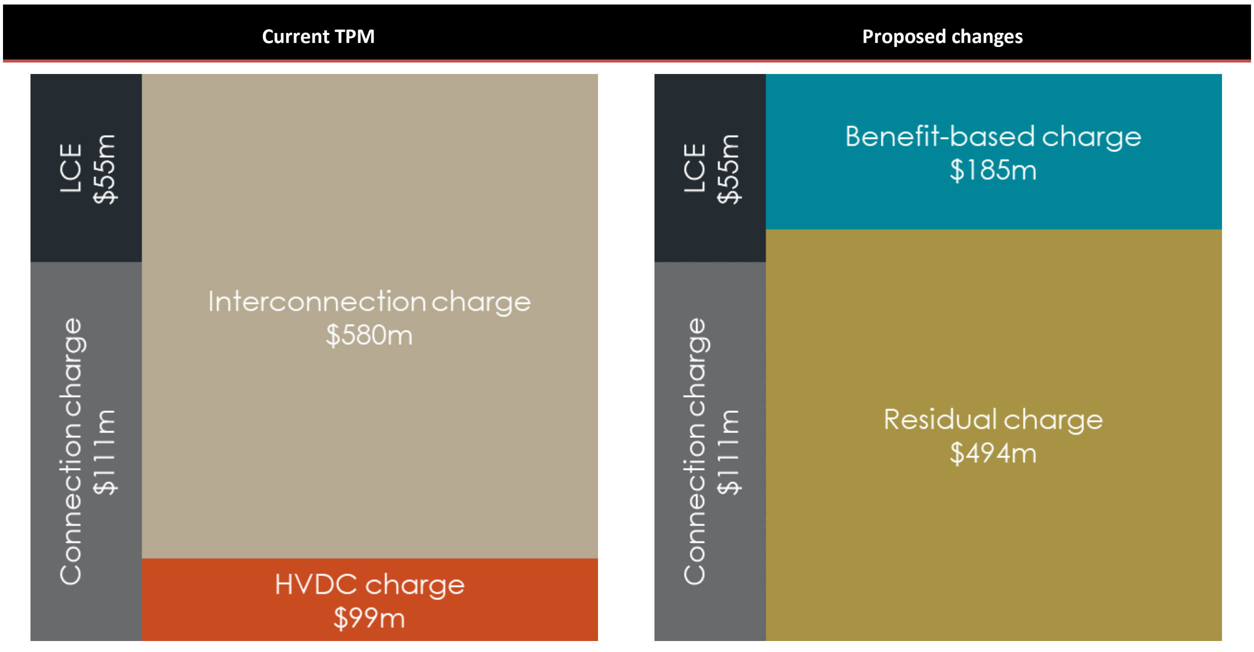
b. The additional components – which must be implemented if Transpower considers that this is consistent with the Authority's statutory objective. Transpower's opinion on consistency can be overruled by the Authority.

   Included in the additional components are a transitional peak demand charge and an ability to extend the benefits-based charge from seven existing assets to all pre-2019 transmission assets.

8.1.2 The Authority's proposal involves a significant change to the structure of the current TPM.

8.1.3 Of the two new elements the residual charge will be the most significant element of the TPM for quite some time. This is depicted in the following Figure 2.1 from the HoustonKemp 2019 Report.

Changes to recovery of Transpower's regulated revenue under EA's proposal, 2020/21



Source: Electricity Authority

8.2 Improvements since the last round of consultation

8.2.1 Trustpower acknowledges and appreciates that the Authority has sought to reduce the complexity of the overall proposal and that the proposal affords greater discretions to Transpower than previously.

8.2.2 However, this level of discretion may prove to be illusory as the TPM Guidelines still contain a default methodology and any changes Transpower may want to make will be assessed against the Authority's default methodology.

8.2.3 The CEC 2019 Report comments that this combination of default terms may create a new problem of regulatory risk:

> *"In a sense, despite their detail, the guidelines do actually provide for a fair degree of discretion, in that Transpower is able to opt for alternatives to – or additions to – many of the prescribed methods. But that creates the opposite problem of regulatory risk. Because the guidelines require that these alternatives are evaluated – by Transpower and then by the EA – against the EA's statutory objectives. To all intents and purposes, this means re-opening this TPM review each time Transpower opts to depart from the prescribed transmission method. In this sense, the new TPM regime may be durable in name but not in substance: pricing methods are liable to be under almost continual review by the EA.*
>
> *This gives the worst of both worlds: a highly prescribed default method, combined with wide regulatory discretion on alternative methods. What is needed is an adaptive but stable middle ground, in which the TPM guidelines provide pricing principles, within which Transpower has discretion to design – and adapt as needed – the most appropriate pricing method."*[35]

8.3 Consistency with statutory objective

8.3.1 We asked CEC to give us an independent view on whether, notwithstanding our views on the statutory objective, the Authority's revised proposal is the best option to promote the overall efficiency of the sector.

8.3.2 CEC's advice is that the work has simply not been done to provide that assurance. In particular, CEC has noted:

a. It is not possible to be confident that static efficiency will be improved under the Authority's proposal as the static efficiency of nodal prices requires deep participation by the load side and this is clearly not the case at the moment; and

b. The Authority's proposal to ramp up nodal prices to improve dynamic efficiency is also unlikely to work unless there are other significant changes to the market design (including in relation to the FTR regime) which have not been discussed.

8.3.3 Problematically, CEC has advised that the proposals are likely to have adverse impacts on reliability:

> *"The response of load to the removal of the RCPD charge could be quite rapid, so there could be worse reliability in the interim"*[36]

and on competition as the instability and opaqueness of the proposed TPM will favour large established players and mean that

> *"Small new entrants are the lifeblood of a competitive market due to their ability to disrupt the incumbents. Under the proposed TPM, they could be substantially disadvantaged, possibly to the extent that they do not enter the market at all."*[37]

[35] CEC 2019 Report, p. 29.
[36] CEC 2019 Report, p. 9.
[37] CEC 2019 Report, p. 37.

8.3.4 In CEC's view:

> *"… the competition leg of the statutory objective implicitly requires that the EA develops a TPM that is non-discriminatory, transparent and stable. The proposed TPM has none of these characteristics and so is unlikely to achieve the competition leg of the statutory objective."*[38]

8.3.5 This suggests that the Authority's proposal is not consistent with its statutory objective (whichever interpretation is adopted).

[38] CEC 2019 Report, p. 38

9 Comments on the Authority's CBA

9.1 Authority's CBA claims substantially more benefits than previously

9.1.1 The Authority's CBA estimates present value net benefits, measured against a status quo in which the existing TPM continues to apply, of $2,711 million in connection with its proposal.

9.1.2 By way of comparison, net benefits of $213.3 million were estimated for the substantially similar proposal published by the Authority in its 2016 proposal.

9.1.3 Trustpower has taken independent advice on the Authority's CBA to understand this substantial increase in benefits.

9.2 Expert advice has highlighted mistakes and errors in its bespoke CBA

9.2.1 HoustonKemp's analysis has shown that the Authority's CBA:

a. has overestimated the benefits and underestimated the costs of its proposal and when these errors are corrected the Proposed TPM Guidelines actually give rise to net costs;

b. contains further errors of assumption and approach that render its results unreliable;

c. does not consider alternative options and incorrectly characterises the status quo;

d. assumes the efficacy of its proposal but does not show this to be the case; and

e. does not actually support reform to the TPM Guidelines in the near term since, even on its own (flawed) estimates, the Authority does not establish substantial net benefits arising from its proposal over the next decade.

9.2.2 We note that TLG 2019 Report for the TPM Group reaches a very similar set of conclusions.

9.2.3 In the balance of this chapter we highlight some of the key elements of the HoustonKemp analysis but urge the Authority to read the report in full.

9.3 Transfers have been incorrectly included

9.3.1 Transfers between two groups are not benefits to society and do not improve economic efficiency.

9.3.2 However, the Authority's estimate of benefits associated with greater use of the grid are dominated by transfers from generators to consumers associated with lower nodal prices.

9.3.3 The vast majority – about 98 per cent – of the change in consumer surplus that the Authority estimates is a transfer, rather than a benefit.

9.4 Significant costs have been inexplicably omitted

9.4.1 As is acknowledged in the 2019 Issues Paper most of the benefits from the Authority's proposal arise from higher peak demand due to the removal of the RCPD charge.

9.4.2 However, higher peak demand also imposes costs on the electricity industry, since it requires greater capacity to be built in the generation, transmission and distribution sectors.

9.4.3 HoustonKemp have advised that the Authority's CBA underestimates these costs because it:

a. assumes incorrectly that the costs of building new generation capacity are incorporated in its analysis;

b. ignores the costs of building new distribution capacity; and

c. underestimates the costs of building new transmission capacity by averaging across scenarios with lower cost outcomes (while not having regard to those scenarios in its estimates of benefits).

9.4.4 HoustonKemp have advised that the Authority's modelling suggests that, relative to the status quo, its proposal gives rise to additional investment in generation capacity of $1,940 million and distribution networks of $292 million in present value terms.

9.4.5 The CBA does not to measure this additional investment as a cost of its proposal. The Authority's modelling framework:

a. takes into account the benefits associated with this decrease in price, consisting of reduced deadweight losses; but

b. does not take into account the costs that give rise to this decrease in price, consisting of additional investment in generation.

9.4.6 Nor does the CBA take into account the costs of removing the RCPD charge on distribution capacity. Instead the Authority simply assumes away these costs away by saying that its cost benefit analysis 'focuses' on transmission.

9.4.7 HoustonKemp point out that this is no more reasonable than a view that its analysis should focus only on benefits, rather than costs.

9.4.8 Distribution costs arise as a direct result of the increased demand that the Authority models as resulting from its reform and giving rise to benefits in the form of reduced deadweight loss. These increased costs impose a cost on society that the Authority must consider in its analysis.

9.5 Including these costs creates a negative CBA

9.5.1 With simple corrections, the Authority's grid use model can be shown to estimate net costs of $2,303 million, rather than the net benefits of $2,593 million that it claims. The composition of these estimates is set out at in the table below.

Description	EA's estimate of benefit	Our estimate of benefit
Change in consumer surplus	$2,579 million	$51 million
More efficient investment in batteries	$202 million	$202 million
Increase in transmission costs	-$188 million	-$324 million
Increase in generation costs	n/a	-$1,940 million
Increase in distribution costs	n/a	-$292 million
Total grid use net benefit	**$2,593 million**	**-$2,303 million**

Source: Electricity Authority, HoustonKemp

9.6 Significant modelling errors have been made

9.6.1 HoustonKemp consider that due to the number and nature of the errors that affect its analysis, no reliance can be placed on the results of the Authority's modelling.

9.6.2 The result of these errors is that the Authority's grid use modelling is likely to substantially overstate the extent to which battery investment would be incentivised under the status quo.

9.6.3 HoustonKemp note that the Authority's modelling of benefits reflects significant reductions in the profitability of the generation sector, arising from substantial new investment combined with reduced generator revenues due to lower prices. Although the Authority assumes that progressively more expensive generators are required to enter the market to serve peak demand under its proposal, the result of these errors is that the increased demand predicted by the Authority leads to lower average wholesale prices, when in fact, more generation investment typically requires higher prices.

9.6.4 These errors mean that, on its own modelling, the effect of the Authority's proposal is to give rise to an additional $1,940 million of generation investment. However, at the same time total generation revenues reduce by $3,655 million. This means that over the modelling period, generators make $5,595 million less profit under the proposal.

9.6.5 The Authority relies upon a single observation around the Commerce Commission's approach during RCP2 with respect to accounting for the benefits of enhanced scrutiny – this does not provide a reliable basis to conclude that 4.4 per cent reasonably represents the expected outcome of this form of scrutiny.

9.6.6 It is incorrect to describe changes to Transpower's expenditure program that follow the Commerce Commission's review wholly as benefits, since a reduction in expenditure may result in fewer services, lower reliability or increased future expenditure; and the basis upon which the Authority considers that stakeholders would not just replicate the outcome of the Commerce Commission's review processes but improve on them is unexplained.

9.6.7 In our view, this basis for estimating the potential benefits associated with additional scrutiny is unreliable and likely to overstate the benefit. HoustonKemp believes that any benefits associated with increased scrutiny are likely to be small, relative to the Authority's estimate. This view aligns with earlier expert advice on this topic.

9.6.8 Moreover, the Authority's estimate of the benefits of durability does not rest on any evidentiary basis. It is more accurately described as an assertion, rather than an estimate. In our view, the Authority should not pursue the calculation of a durability benefit – a benefit that in any case assumes net benefits associated with its proposal that have not been established.

9.6.9 We also note HoustonKemp's views that the CBA has not followed best practice, having incorrectly specified the status quo:

> *".. specifies the status quo in all scenarios by inappropriately assuming that the RCPD charge would remain at the current strength and give rise to inefficient outcomes, notwithstanding Transpower's ability to change this under the current TPM guidelines."*[39]

9.6.10 The Authority appears to be wholly persuaded of the merits of its proposal on the basis of economic principle and the purpose of CBA in its 2019 Issue Paper is limited to verifying the magnitude of the benefits that would be realised by its proposal, rather than seeking to test these in any meaningful way against other options.

9.6.11 By way of example, the Authority proposes to reallocate the costs of historical investments, without presenting an alternative option that does not do this. However, on the Authority's own estimates, excluding historical investments from the benefit-based charge gives rise to net benefits of $18 million.

9.6.12 The greatest net benefits are achieved if the proposal is implemented so as to come into effect in 2034 (with the proposal resulting in increasing costs to consumers before then). This timing gives rise to net benefits that exceed immediate implementation costs of the Authority's proposal by $87 million in present value terms.

9.6.13 Caution regarding the uncertainty of future developments, and the results of the Authority's CBA itself, suggest that efficient operation of the industry would be promoted by a slower implementation of the proposal than is being considered by the Authority.

[39] HoustonKemp 2019 report, p. vi

9.6.14 This may lead to a need to reassess the Proposed TPM Guidelines themselves depending on the outcome of the CBA.

9.6.15 Given that an open mind on the above consultation means that the Proposed TPM Guidelines may require further change, an alternative way forward for the Authority would be to undertake a proper and fulsome CBA now that includes assessment of the various additional components (in their various possible combinations).

9.6.16 The HoustonKemp 2019 Report concludes that

> *"The multiplicity of errors made by the EA in the conceptualisation, formulisation and implementation of its analysis makes a simple 'fix' to these errors impractical within the timeframe provided by this consultation"*[40]*.*

[40] HoustonKemp 2019 Report, p. ii.

Part IV

10 Peak charges should be a core component of the TPM

10.1 Peak prices provide a stable and clear signal

10.1.1 The Authority has invited feedback on whether a peak charge should be a core component of the TPM[41].

10.1.2 Our view is that peak prices should be a core component of any replacement TPM Guidelines. Peak prices provide a simple, effective, long-term signal which contributes to competition in a relatively small market (particularly at the nodal level).

10.1.3 As noted in Chapter 7, any issues with the strength of the RCPD can be managed under the existing TPM Guidelines. Alternatively, a new bespoke peak charge could be designed by Transpower.

10.2 RCPD facilitates valuable load control

10.2.1 Retaining a RCPD charge will facilitate the continuation of distributors' hot water load control, which is an established feature of demand-side management in New Zealand.

10.2.2 For over sixty years load control has provided a reliable means for load-shifting with minimal impact on customers, with customers typically able to opt in or out of this services and being rewarded with a lower rate for controlled hot water consumption.

10.2.3 We also note that once the investments are in place for load control services, a level of peak control can be achieved at low cost, i.e. customers hardly notice a moderate level of hot water control, and batteries can be operated to jointly control load peaks and to respond to any price arbitrage opportunities.

10.2.4 Maintaining peak pricing will enable load control to continue to be relied on while other forms of demand-side management develop and become available over the medium term.

10.3 Peak charges are also justified by wider context

10.3.1 When the wider contextual factors are taken into account, we think there is a strong case for maintaining a peak charge as it will have low transaction costs and is low risk. Such a charge will ensure better outcomes with respect to the level of investment in batteries, demand side response etc.

10.3.2 We note that once a greater level of demand side options have been developed, they will represent a low-cost effective solution that avoids the need to consistently overbuild the grid. This is consistent with the broader approach adopted by the Commerce Commission with respect to transmission investments.

10.3.3 We also note that a peak charge will:

a. likely be particularly important in relation to ensuring appropriate investment in electric vehicle charging infrastructure as well as being important for fair and efficient pricing for customers with rooftop solar, without reliance on major changes in market structures and hedging arrangements in order to achieve the nodal price nirvana; and

[41] It is worth noting that the benefits claimed in the CBA associated with this element of the change proposal (which in any event we dispute) are related to a *reduction* in the RCPD. No analysis has been undertaken of the effects of the *removal* of the RCPD charge. This is an important omission.

b. provide good signals for load shaving and managing constraints, while being self-adjusting and self-limiting, and less susceptible to cost shifting behaviours.

10.3.4 To the extent that there is some over-investment in batteries this is more likely than not to provide benefits in the form of delayed distribution and increased capability to accommodate a higher level of intermittent resources (wind and solar) consistent with the Government's decarbonisation ambitions. It is also worth noting that batteries can potentially be moved from region to region, thereby requiring an enduring price signal to maintain the peak control provided by batteries.

10.4 Expert views agree a peak demand charge is needed

10.4.1 CEC explains that the alternative of load curtailment to constrain capacity to grid is highly inefficient:

> *"Load curtailment is highly inefficient, for two reasons. Firstly, it is fairly indiscriminate: high-value load is curtailed along with low-value load. Ideally, the low-value load would participate in the auction (directly or indirectly) and have voluntarily self-curtailed, thus avoiding the need for the high-value load to be curtailed administratively. So greater auction participation would have successfully sifted the low-value load from the high-value. In its absence, crude administrative curtailment cannot do this.*
>
> *Secondly, load curtailment it will generally occur unexpectedly, meaning that the consumer cannot prepare for it. In contrast, a consumer participating in the auction would have prepared to self-curtail and would have been able to do so at much lower cost.*
>
> *In short, the level of load curtailment – or the flipside of this, the level of reliability – is a key factor in how efficient nodal prices are in a static sense. So, would raw nodal prices (ie with the existing RCPD charge removed) lead to reduced reliability and so poorer efficiency?*
>
> *The EA has not satisfactorily explored or addressed this question at anything deeper than a cursory and theoretical level. It would be a bold step to carry out a real-life experiment by removing the existing RCPD charge and seeing what happens. "*[42]

10.4.2 The Culy Report confirms that errors and inappropriate assumptions concerning battery investment and operation have led the Authority to overstate the potential risk of excess "inefficient" battery investment in response to the current RCPD price signal by a factor of around 6x.

10.4.3 The Culy Report re-modelled battery operation and shows that although the current high RCPD price may provide too strong a signal for battery investment, this is not a significant efficiency issue for 10 years until battery costs fall significantly:.

> *"The more "fit for purpose" modelling of battery operation presented here shows that the current high RCPD price may provide a strong signal for battery investment, but this is not a significant efficiency issue for 10 years until battery costs fall significantly. Even if this efficiency issue grew over time, then it could be easily eliminated by phasing down the strength of the RCPD signal to a lower level over time as and when changes in technology and the market became more certain. "*[43]

10.4.4 TLG 2019 Report considers that it is:

> *".. neither necessary nor appropriate to switch away from an RCPD-based charge at this time, though there is a case for recalibrating the RCPD charge …."* [44]

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[42] CEC 2019 Report, p. 6.

[43] Page 5

[44] TLG 2019 Report, p.2.

10.4.5 TLG 2019 Report explains the importance of close management of the RCPD signal to ensure appropriate balance between static and dynamic efficiency is obtained:

> *"Peak demand or other types of potentially "avoidable" costs (like the RCPD charge) therefore constitute both a risk and an opportunity – and they should always be seen in both lights. Clearly, if the RCPD charge is too high or too narrowly focussed, its impact can be too great. But if the RCPD charge is retained and calibrated, it continues to provide a simple signal that elicits valuable information about behind the meter supply elasticity (choice). As such, there can be considered to be an optimal amount of avoidance behaviour, one that limits short-term static inefficiency while at the same time still providing information on consumer preferences and choice critical to long-term dynamic efficiency. A charging structure should be designed with these competing interests in mind."*[45]

10.4.6 TLG 2019 Report also states that:

> *"Just stepping back and looking at New Zealand from an outside perspective, it seems odd and problematic to propose removing a charge that (when calibrated) increases competitive pressures, even if imperfectly, in favour of removing the RCPD entirely and relying even more on a wholesale spot market that is, at best, just workably competitive on average over time …."*[46]

10.4.7 Based on this advice we think the case for change to entirely remove a permanent peak transmission charge has not been made.

[45] TLG 2019 Report, p. 13.
[46] TLG 2019 Report, p. 28.

11 Adequacy of nodal prices to address efficiency

11.1 Expert advice on the role of nodal prices

11.1.1 The primary reason for removing the RCPD charge is because the Authority believes nodal prices are all that is required to address efficiency. It quotes the International Energy Agency's prior comments around locational marginal pricing as rationale for this view:

> *"Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments".*

11.1.2 This led the Authority to form a different view from Transpower on the value of peak signals to minimise grid expenditure.

11.1.3 We asked CEC to advise us on the whether nodal prices are sufficient. The CEC 2019 Report advices that whilst in theory nodal prices could be sufficient to promote efficiency, this is an ideal state that certainly does not apply in the current New Zealand market.

11.1.4 The Authority acknowledges this issue and suggests extra penalty functions could be incorporated into the SPD process to deal with the risks as grid security standards are approached. However, whether the Authority actually intends to make this future change to the wholesale settings is unclear.

11.1.5 The CEC 2019 Report considers the Authority's solution further and finds that it would be impractical given the extreme nodal price volatility that would be implied, and in any case would take many years to design and implement. Until this is implemented a peak transition charge would be required

11.1.6 The CEC 2019 Report further notes that:

> *"There is no reason to suppose, ex ante, that the level of transmission capacity just happens to be exactly the right amount for the nodal price difference to equate to the long-run transmission cost. Indeed, the EA makes the comment that:*
>
> > *"users may never see the full costs of their actions because [transmission] investment is usually triggered 'early', before nodal prices have risen to levels commensurate with signalling that additional investment would be beneficial" (E.80)*
>
> *Which I interpret to mean that, under current investment policies (and the issues paper refers specifically to the Grid Reliability Standards (GRS)), nodal prices will be below the level required to promote dynamic efficiency.*
>
> *In summary, it is unlikely to be the case that nodal prices promote dynamic efficiency and so they are not "best" in that respect, whatever meaning the EA intended. To be clear, this is not to criticize the NZ spot market design, which is rightly considered a "gold standard" design. It just reflects the fact that it is not just the spot market, but also transmission investment policy, that determines the long-run level of spot prices."*[47]

11.1.7 The Authority is aware that the full implementation of real time pricing is a key precursor to reliance on nodal prices for peak signals. Real time pricing is itself a number of years away. However, once is it in place, as explained by CEC, the transmission scarcity pricing that it will enable will serve to further increase the volatility and unpredictability of nodal prices with adverse implications for retailers.

[47] CEC 2019 Report, p. 7.

11.1.8 Firstly, as is explained by CEC the volatility of nodal prices will undermine the ability of investors to make efficient investment decisions:

> *"… volatility will inevitably impact on dynamic efficiency, because a necessary part of any user investment process is to forecast of nodal prices. Even if these "fixed" nodal prices could in principle, signal the long-run costs of transmission, that is of no consequence if it is practically impossible for the investor to forecast these and so incorporate them into its investment decision."*[48]

11.1.9 Secondly, there is significant question around how the risks associated with volatility of nodal prices will be managed. As CEC notes, it is unlikely that these risks will be passed to directly to mass-market consumers:

> *'If consumers face these prices, this would inevitably create bill shock, confusion and concern. In fact, it would probably not be politically or practically feasible to expose consumers to such uncertainty."*[49]

11.1.10 While retailers typically manage risk on the behalf of consumers, this effectively results in higher prices to accommodate a reasonable risk premium. However, there is also a question of how retailers will manage these risks.

11.1.11 As CEC explains, retailers can currently manage energy price risk by purchasing hedges from generators, but can only hedge some transmission risks using FTRs, leaving them with significant exposure where hedges are not available:

> *"A retailer can hedge its energy price risk by buying a hedge from a generator. But if the generator and retailer are located at different nodes, the retailer remains exposed to the price difference between the two nodes. A retailer can then buy a financial transmission right (FTR) to hedge nodal price differences, but only at nodes for which FTRs are available. It will still be left with the risk of price differences between its node and the nearest FTR node.*
>
> *These unhedgeable risks are perhaps not a major issue currently for retailers. But the introduction of RTP will create new risks from nodal scarcity pricing; that is, scarcity pricing of transmission (as opposed to energy). The EA's idea, discussed above, would supercharge this risk. As a rule of thumb, long-run transmission costs are around 50% of total transmission cost. The LCE is currently only around 5-10% of total transmission cost. So achieving dynamic efficiency from nodal prices would involve increasing nodal price differences by a factor of 5 to 10, meaning retailer risks would rise by a similar factor. This would, at the very least, make standalone retailers unviable and so substantially reduce competition. It is not clear whether even a gentailer would be willing or able to incur this level of risk."*[50]

11.1.12 Even if FTRs could be extended to provide hedges across all nodes this would be a huge undertaking and almost impossible for any but the largest of retailers to manage. The alternative to acquiring an FTR to manage nodal price differentials would be investment in batteries or demand side solutions to act as a physical hedge.

11.1.13 These issues have not been addressed in the Authority's analysis.

11.2 The effects of lumpy transmission investments on dynamic efficiency

11.2.1 Transmission investments are lumpy and investments that need to be made ahead of time to achieve economies of scale and scope. As a result, it is unclear that nodal prices will ever be effective at promoting dynamic efficiency. Experts agree.

11.2.2 As TLG explains, in these scenarios Locational Marginal Prices (**LMP**s) will not deliver the conditions needed to support investments:

[48] CEC 2019 Report, p. 8.
[49] CEC 2019 Report, p. 8.
[50] CEC 2019 Report, p. 8.

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

The effectiveness of price signals to motivate or incentivise or support efficient behaviours depends on the absence of material market failure. A small market in which most investment decisions are also correspondingly small may meet that condition. But transmission projects are often larger and lumpier and are justified for reasons that extend beyond merely LMP differences. As such, the impact of transmission investments once approved and built is necessarily disproportionate and depressive. Market prices will always be lower if transmission projects augment capacity for reasons other than LMP differentials. Market prices will also be lower to the extent that it is necessary to invest ahead of full demand because of scale or scope given the lumpy nature of transmission projects. Accordingly, in any quasi competitive market simulation, such impactful investments would not ever be made unless they are supported by a corresponding long-term contract. The RCPD charge acts like such a contract. It is also a signal, which has value because LMPs will not be sufficient and beneficiaries will be too diverse and uncertain in all or even most transmission investment cases."[51]

11.2.3 The CEC 2019 Report also explores the effects of lumpy investments in causing nodal prices to be ineffective:

"In summary, lumpiness can cause nodal prices (even dynamically-efficient ones) to be ineffective in situations where the arrival of a new generator prompts immediate transmission investment, and these are the examples that the EA focuses on. But there will be many other situations where transmission investment would not occur. To assess efficiency impacts, a systematic and comprehensive analysis must be undertaken. Cherry-picked examples of possible inefficiency present a distorted picture.

More generally, it is not clear that lumpiness will act to suppress the level of nodal prices differences overall, because it gives rise to two opposite effects that are liable to cancel out. On the one hand, a new lumpy investment will remove congestion, possibly for a considerable period, and so will set spot transmission prices to zero. So, this would suggest that lumpiness will generally act to suppress these spot prices. But, on the other hand, lumpiness makes an investment project more costly, meaning that Transpower will be prepared to tolerate a greater degree of congestion before new investment becomes economic. So, this acts to raise these spot prices.

In short, lumpiness causes lower prices at the front-end of the investment cycle but higher prices at the back-end. The overall impact of these two offsetting effects is unclear. Some detailed, quantitative analysis is needed to identify whether lumpiness is a critical flaw in the use of nodal pricing concepts as a framework for developing efficient transmission prices."[52]

11.3 Role of load control and demand side response

11.3.1 The Authority speculates that over time there will be a greater amount of demand response which will mean that nodal prices will be less volatile.

11.3.2 In our view there is a high degree of uncertainty as to whether these developments will unfold in the way that the Authority expects. Factors that will affect whether or not the Authority's expectations are met include:

a. the rate at which the cost of batteries falls, which is still largely an unknown;

b. uptake of batteries; and

c. development of technology for retailers/aggregators to manage load.

[51] TLG 2019 Report, p. 32.
[52] CEC 2019 Report, p. 13-14.

11.3.3 The analysis of battery demand response presented in the Culy Report finds that the Authority appears to have drastically overstated the effect of load-shifting through batteries that could be achieved during peak and shoulder periods in response to price signals.

11.3.4 While the Authority acknowledges the risk that distributors may reduce, possibly abruptly, load control in response to the removal of the RCPD charge, it finds that there are a number of factors which reduce this risk. As a result, it concludes that Transpower has overstated the risks relating to load control. In coming to this conclusion, the Authority appears to make a number of assumptions regarding the way in which load control is likely to function.

11.3.5 One of the reasons that the Authority gives for considering that Transpower has overstated the risk associated with load control reducing in response to removal of RCPD pricing is that:

> *It seems likely that the time of a distributor's peak will tend to be correlated with the time that relevant transmission circuits are congested. In that case, distributors may control load on the circuit as a by-product of managing their own networks.*

11.3.6 Constraints on a distributor's network are likely to be localised – for example, to specific feeders – and so load control for the purposes of deferring distribution investment may be limited to specific areas. As a result, the quantity of load control aimed at deferring distribution network investment may be only a fraction of what would have occurred in response to RCPD signals that relate to demand for the distributor's entire network.

11.3.7 Another reason given by the Authority as to why Transpower's paper may overstate risks regarding load control is that it considers that distributors (especially those owned by consumer trusts) are likely to have an incentive to act in the best interests of their customers.

11.3.8 By this, the Authority presumably means that distributors would load control at times of high nodal prices. This seems questionable as volatile nodal prices are unlikely to be passed through to consumers anyway (as explained by the Authority).

11.3.9 Moreover, if distributors were to engage in the use of load control to respond to spot transmission prices, it may be expected that distributors would be observed currently using load control during periods of high spot prices. Trustpower does not observe this behaviour by distributors.

11.3.10 Load control by distributors provides a stable means for reducing peaks and minimising transmission investments. Removal of the RCPD signal and reliance on transmission nodal prices to manage demand to capacity constraints would seem to be a very risky proposition. We are unconvinced by the Authority's attempts to rebut Transpower's findings on this issue.

11.3.11 In sum, Trustpower is of the view that there are serious risks associated with relying on spot transmission prices to constrain grid use to capacity and that by accepting these risks the Authority would be taking an unnecessary gamble with the stability of the transmission system.

12 Comments on benefits-based charges

12.1 Purpose of benefit-based charging

12.1.1 The Authority considers that benefit-based charging will enhance the overall efficiency of the sector. Likewise they consider they will enhance durability by adhering to its "*pay for what you get*" principle.

12.1.2 In this chapter we explain why we do not agree that benefit-based charging will achieve these objectives in relation to either future applications or when applied for existing assets.

12.2 Retroactive application of benefits-based charge

12.2.1 In previous submissions there has been very little support from experts for the retroactive application of benefits charges. As the Covec Report[53] pointed out, twenty experts opposed applying benefits-based charges to existing assets, and there were strong challenges to the two who supported such an application.

12.2.2 As noted previously, the CBA shows there is a cost of $18m of applying the benefit-based charges to existing assets. Nevertheless, the Authority proposes to apply the benefit-based charge for seven existing assets.

12.2.3 TLG observe that the beneficiaries of the seven historic investments considered by the Authority to be candidates for retroactive charges are spread broadly and evenly across the country, which appears to negate the proposition that retroactive charges are required for durability as a result of fairness concerns:

> *"Moreover, the 2019IP analysis shows that the beneficiaries of these investments, when considered in aggregate, are spread rather broadly and evenly across the country (covering both North and South Island), with no clear case to suggest that the benefits are accruing disproportionately to a small group of customers in a given area. With this in mind and given the major limitations in implementing a benefits-based approach described earlier, there is not a definitively strong case for altering the charges applied to these legacy investments. With the broad spread of benefits observed, a much simpler modification of the current RCPD approach for recovering these costs is likely to achieve the same outcome.*[54]

12.2.4 As TLG also argues:

> *"We note that the Authority's analysis does not suggest material trapped value can be released by revisiting the legacy projects. The argument instead is merely one of durability by making a change to honour a new principle. In our view, switching principles undermines durability. It is signalling that tomorrow there may yet another principle that can be used to review today's agreement. Unless there is material value or market distortion being fixed or a change to actually implement what was previously agreed, we would not normally see a case for changing the way a legacy asset is treated in a regulatory context."*[55].

12.2.5 The CEC 2019 Report comments on the durability of the proposed regime given the proposal to include some historical assets into the benefit-based charge, but not all:

> *"In proposing to include some – but not all – historical assets in the BP regime, the EA has opened up a new front in which winners and losers can do battle over the existing cake. Furthermore, by proposing to allow Transpower to re-open whatever set of assets the EA finally decides upon, the EA has allowed this battle to continue into the operation of the new regime."*[56]

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[53] Covec, *Review of expert reports on transmission pricing*, February 2017
[54] TLG 2019 Report, p.21.
[55] TLG 2019 Report, p.21.
[56] CEC 2019 Report, p. 27.

For there to be some reasonable certainty and stability in this battleground, the EA would need to articulate some clear principles to guide the choice of assets. The EA has failed to do this. In fact, it has made things even worse by choosing to include only those recent assets that show a positive net benefit. So a proxy battle will now be fought over the benefit modelling of each asset."[57]

12.2.6 Trustpower finds it concerning that with such a weight of evidence against retroactive application of benefit-based charges and the results of the Authority's own CBA discussed previously, the Authority continues to include it in the Proposed TPM Guidelines.

12.3 Comments on the Authority's benefits-based allocation for the seven existing assets

12.3.1 We are concerned with the modelling approach that has been adopted by the Authority in relation to applying benefits-based charges to the seven existing assets.

12.3.2 The Proposed TPM Guidelines seek to address the difficulties of modelling the beneficiaries of assets after they have been built by providing for a mandatory allocation. This is not a guideline.

12.3.3 Setting that issue aside, we decided to undertake some case studies to better understand how benefits-based pricing allocations work. These are presented in Chapter 15.

12.3.4 Case Study 1 shows the extent to which the Authority's determination of the benefits for the Wairakei Ring investment using vSPD:

a. is highly sensitive to the choice of counterfactual;

b. involves a range of input assumptions and methodological choices that will materially affect the modelling results; and

c. calculates benefits over a historical period instead of being a forward-looking grid investment assessment as would be used by Transpower going forward[58], including for any existing assets if they are reopened.

12.3.5 As a result, we consider there are serious prospects of future disputes in the event that the allocations determined by the Authority differ from eventual outcomes. This will have implications for the durability and efficiency of this charging regime.

12.3.6 Further additional modelling that we have carried out demonstrates that, even if the Authority were to take a forward-looking approach to modelling benefits, the forecast error inherent in any such exercise means that actual benefit allocations may be significantly different from actual benefits (Case Study 2).

12.3.7 Our additional views on the appropriateness and adequacy of the benefits-based modelling work undertaken by the Authority are presented in Appendix C.

12.4 Other issues with benefits-based charges

12.4.1 As noted earlier, the CEC 2019 Report identifies two fundamental flaws in benefit-based charges – namely the opacity and dilution of this charging mechanism.

12.4.2 In addition, in our previous submissions Professors Bushnell and Wolak explained that:

a. identification of benefits accruing to individual customers are difficult and contentious because customers' benefits are interdependent;

b. the temptation to free ride on transmission investment assets means that at the point that the benefits are being identified for the purposes of determining benefit-based charges, potential beneficiaries have the incentive to understate the benefit that they are likely to

[57] 2019 CEC Report, p. 27

[58] We note that Transpower's assessment of grid investments would typically assess the potential impacts of a transmission investment using a range of potential future scenarios over several decades, considering issues such as technology development, demand growth, entry and exit of generation.

receive, meaning that the process of determining benefit-based charges is likely to be contentious; and that

c. this could result in significant delays to transmission investments[59].

12.4.3 These are sentiments echoed in TLG 2019 Report, which finds that the benefit-based charge as currently described is not sufficiently scoped to provide a tractable solution, and that most projects simply do not warrant this more focussed consideration of beneficiaries:

> *"These issues cannot be resolved without a fully coherent framework, the absence of which should be deeply concerning to the Authority and all stakeholders. Without a suitable framework, there will be additional costs associated with moving to a theoretically more efficient framework but one whose implementation is incoherently structured and thus (even) more prone to argument. Let there be no doubt that once unbound from the current simple allocation methodology, stakeholders will argue vociferously, using combinations of signal and noise, with rent-seeking and rent-rejecting activities that will be hard to disentangle. The 2019IP does not appear to have considered these costs of disputation and how it varies depending on the extent and spread of benefits. Many projects would simply not benefit from more focussed consideration beyond what is normally done."*[60]

12.4.4 TLG's analysis suggests that there are simply too many unanswered questions about how, what may at first appear conceptually appealing, would work in practice to deliver the benefits the Authority predicts, There is no comprehensive elucidation of how benefits would be defined, or how important (and non-trivial) matters like project risks and intertemporal benefits would be treated as part of this framework.

12.4.5 The HoustonKemp report prepared for Trustpower in February 2017 also explains that in reality decision-making is unlikely to be significantly improved for the majority of customers under a benefits-based charging arrangement:

> *"The area-of-benefit charge and the shadow price will not provide the signals intended by the EA due to the process by which investment decisions are made and the timeframe over which this occurs. In order for them to take actions as the scheme intends, customers must understand in detail the process by which charges are set and, furthermore, anticipate the benefits that they and others will receive, and the relative costs the will bear. Although some market participants may well be sufficiently sophisticated to conduct themselves in this way, the objective is likely to be undermined by some key uncertainties that fall outside the control of individual consumers but nevertheless will ultimately influence the process by which their decisions will flow through to investments."*[61]

12.5 Reason why the efficiency objective may not be obtained in practice

12.5.1 Transmission charges set by Transpower according to the TPM Guidelines are simply an input into the chain of pricing that eventually produces a price for end customers.

12.5.2 The Authority assumes complete pass through of signals from its regime. However, an obvious roadblock for distributors and retailers in passing through fixed charges are the LFC regulations, which mean that in practice the recovery of transmission charges from a large number of customers will not be through a non-distortionary fixed charge, but instead from prices that relate to usage.

12.5.3 Even where the LFC regulations don't constrain prices, there are numerous practical issues associated with passing through a charge that is allocated based on historic demand. For example,

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[59] We note that Transpower has similarly highlighted the concern that application of benefit-based charges is likely to delay transmission investments previously with the potential to adversely affect the necessary investment in generation and transmission networks, including that required to meet our future energy needs.

[60] TLG 2019 Report, p. 21.

[61] HoustonKemp report (February 2017), p. 13.

direct pass through by distributors of benefits-charges that are fixed based on historic demand would mean that:

a. New connections installed after a benefit-based charge has been implemented would attract a lower monthly network charge than connections that existed at the time of the charge was introduced; and

b. Customer charges would not reflect changes in circumstance eg, a new tenant that has significantly lower usage/capacity than a previous tenant would continue to pay a fixed charge based on historic demand.

12.5.4 If distributors did choose to directly pass-through the fixed allocations of benefit-based transmission charges, then this would create a huge number of distortions and is highly unlikely to be durable.

12.5.5 Distributors may well choose to avoid these difficulties by recovering costs according to current usage, with the result that the distortions/avoidability that the Authority assumes it has removed by requiring the benefit-based charge to be fixed, will in fact occur.

12.5.6 Notably, distributors' attempts to take a more pragmatic and durable approach to how they pass through benefit-based charges will distort choices between distributed load and load that is directly connected to the transmission grid.

12.5.7 In short, the application of benefit-based charges is likely to lead to a plethora of distortions that have not been identified and may only become apparent once it is implemented.

13 Recommended amendments to Proposed TPM Guidelines

13.1 Simple variations will improve practicality and stability

13.1.1 In the previous chapters of this submission we have outlined a strong case for the Authority to stop this reform, as it has not been appropriately justified, and consider other more moderate reform options.

13.1.2 However, if the Authority decides to proceed with the reform we recommend the following changes:

a. A revised and weakened peak charge that reduces over time and may, for example, transition to a LRMC charge. This should be applied to net load, with the specification, measurement and application to be determined by Transpower (including whether a national or regional approach is adopted);

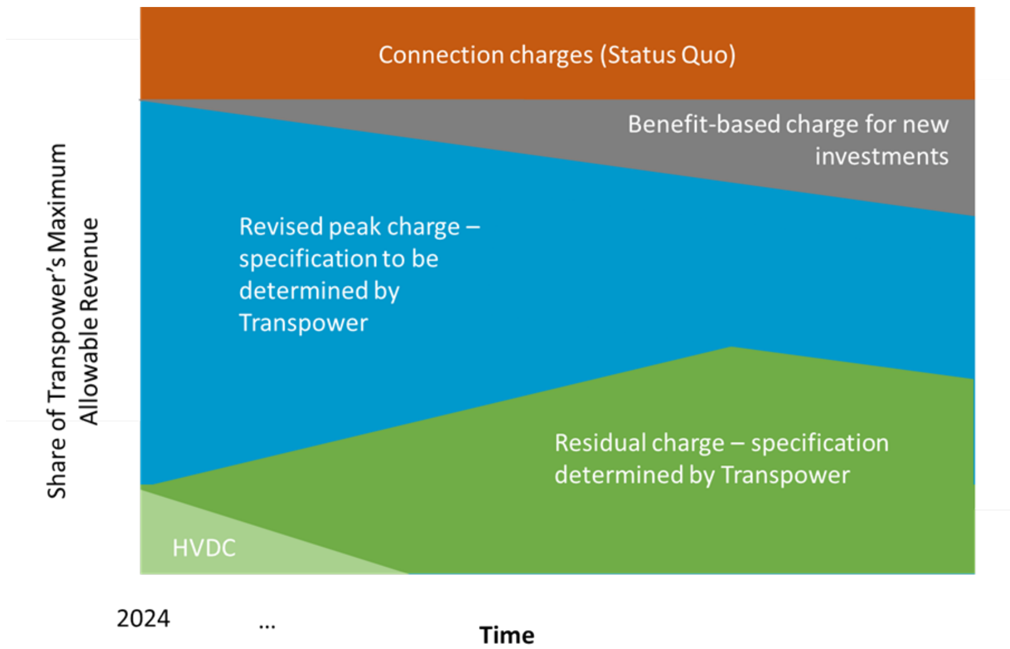
b. A residual charge applied to net load, with the specific details to be determined by Transpower, subject to the dual criteria of being durable while minimising distortions;

c. Incorporation of the HVDC charges into the residual, with a 5-year transition;

d. A broader transition path to avoid price shocks, which is achieved by the proportion of charges recovered through the peak charge declining to a lower permanent level; and

e. The benefit-based charges would not apply to existing assets but would be confined to new investments where the beneficiaries can be clearly identified, with the details of the methodology to be determined by Transpower[62].

13.1.3 Our proposed variation to the Authority's proposal is illustrated in the following diagram[63]:



[62] To be clear, we do not support any application of benefits-based charges but rather have provided this suggestion within the context of the Authority's proposal to adopt this type of charging approach.

[63] The chart reflects the changes that would occur incrementally from the implementation date of the new TPM which has been indicated by Transpower to be realistically around 2024.

13.2 Amendments to the HVDC charge

13.2.1 Under our proposed variations the HVDC charge would be included in the residual charge on the basis that recovery in this way both avoids:

a. distorting spot prices through recovering via load instead of generation; and

b. would also avoid the distorted incentives that have occurred for investment in South Island generation due to the full recovery of the HVDC charge from South Island generators.

13.3 Amendments to the application of the benefits-based charge

13.3.1 We suggest a more targeted application of the benefits-based charge for new investments.

13.3.2 This aligns with expert advice.

13.3.3 CEC suggest a deep connection charge (hybrid benefit-based charge) that would enable beneficiaries of assets to be clearly identified:

> *"A deep connection charge would be similar to a BP charge in that the* ***costs of the shallow asset would be shared between local users in proportion to the attributable benefits****. However, unlike the BP charge (but similar to a connection charge), it is a one-off charge that is applied when a new user connects. So, it is something of a hybrid between the BP charge and the connection charge."*[64] *[emphasis added]*

13.3.4 Similarly, TLG suggest that the benefits-based charges should be applied only where there is a localisation of benefits and that a rule could be developed to assist in identifying these circumstance:

> *"If the EA intends to proceed with any benefits-based methodology it should be limited to specific situations where there is unambiguous localisation of benefits (such as more than 60 or 70 percent), otherwise cost recovery should default to a broad-based framework for simplicity and to dispute avoidance"*[65]

13.3.5 And further that[66]:

> *"On the flipside, investments that touch, say, 60% or more stakeholders with impacts on both islands could be automatically handled by the default approach. Any project in between might be reviewed in terms of the nature of the benefits, timing, and other considerations before being assigned to the default or beneficiary approach."*[67]

13.3.6 We also recommend that benefits-based charges would be allocated to beneficiaries on the basis of net load, with Transpower having discretion to determine the specifics of the allocation methodology used according to guiding principles of durability while minimising distortions.

13.3.7 Collectively these variations will:

a. provide a managed pathway towards reliance on nodal prices to deliver effective signals for managing congestion and grid use;

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[64] CEC 2019 Report, p. 19
[65] TLG 2019 Report, p. 8
[66] TLG recommend, however, that first and foremost there must be clarity of the nature of benefits being evaluated: "*Before being able to accurately assess projects in this way, there must first be agreement as to the nature of the benefits that are being evaluated. A government policy statement is needed to provide clarity on this. Otherwise, what is the point of adopting a beneficiary pays approach if one is not actually able to consider all the possible types of benefits in a holistic way, and must assess benefits that can be identified without guidance as to how to handle risk, inter-temporal impacts or other issues. A policy statement would provide useful and timely guidance as to how to treat the myriad of special and diverse cases likely to arise in adopting a beneficiary-pays system*."
[67] TLG 2019 Report, p. 22.

b. allow sufficient time for the necessary tools to be developed so that participants can effectively manage their exposure to more volatile nodal prices;
c. reduce the distortions of the existing strong peak price signals provided by the existing RCPD charges, while avoiding the disruption of entirely and abruptly removing a peak signal (or the uncertainty associated with peak pricing being only a possible option);
d. reduce the complexities and distortions of a broad application of benefit-based allocation of common costs by applying the benefit-based charges only in circumstances where the beneficiaries can be appropriately targeted;
e. provide a transition path to avoid price shocks, without the need for complex price caps; and
f. are complementary to distribution charges and recognises that transmission charges are ultimately passed to distributed load customers through network prices set by distributors.

14 The Authority's proposal is not supported by overseas precedent

14.1 Peak charge allocators are the norm

14.1.1 To the best of our knowledge, no other jurisdiction in the world has adopted an approach of relying purely on spot transmission prices and not having an enduring peak demand charge of some description. While the Authority highlights a number of "transitional" issues, it seems to grossly understate the importance of these and, importantly, the associated risks.

14.1.2 TLG 2019 Report notes:

> *"Taken together as a package, the changes proposed in the 2019IP would put New Zealand in a unique position worldwide in relation to how granularly it would implement transmission pricing in an LMP-based energy-only wholesale market environment at a time when the one thing everyone can agree on is that the future is not going to be much like the past. Is the full scope of change necessary? At this time? No and no. An impactful but moderated approach can achieve all material benefits within a framework that remains familiar, understood, and established."* [68]

14.1.3 The flaws with a reliance on LMP are summarised well by TLG 2019 Report which states:

> *"Whereas LMPs are calculated in New Zealand, it is not the case that the values calculated automatically have all of the properties that an LMP is theoretically supposed to have under the conditions where you can rely on LMPs as a stand-in for any other form of transmission charge.*
>
> - *First, LMP is only a short-term in nature and amounts to a volatile competitive market price signal often without a corresponding long-term contractual hedge available.*
> - *Second, the New Zealand market is small with workable competition at best. The transmission network is long and stringy with many implications for competition and reliability and relatively fewer projects that would be dominated by economic considerations.*
> - *Third New Zealand is committed to decarbonisation which automatically infuses all planning scenarios and stakeholder expectations with the likelihood or even inevitability of future policy intervention or guidance to assure achievement – with likely implications for transmission development that go beyond LMP considerations.*
> - *Fourth, the wholesale market itself has been subject to numerous reviews – some quite deep and wide-ranging – canvassing market structure, market power, hedge market performance, hydro management, dry year reserve policy, and retail pricing. LMPs may be technically mature in New Zealand, but the market is no more insulated from broader forces and factors than any other.*
> - *Fifth, many, if not most, of Transpower's proposals will have a significant "reliability" or other benefits component. Little of these benefits will have much to do with LMPs, though the projects may affect LMPs of course. To the extent such investments occur, they should manifest themselves through broad based charges not unlike a recalibrated RCPD charge suggesting that an RCPD type charge would be better than LMP at incentivising competition from possible alternatives more efficiently.*
>
> *None of these broader considerations fit neatly in the efficient market model – they are, however, practical factors that stakeholders must try to anticipate and balance. Neither the LMP side of that equation, nor the beneficiary pays part of that equation are perfect enough to move entirely away from an RCPD-type charge."*[69]

14.2 The US experience does not provide a precedent for benefit-based charging

14.2.1 The basis for the Authority's proposed beneficiaries pays charging approach derives from the pricing principles applied by multi-state system operators in the United States for allocating the

[68] TLG 2019 Report, p. 9.
[69] TLG 2019 Report, p. 24-25.

costs of transmission assets which are often owned by multiple parties and provide an interconnection service between states.

14.2.2 We do not consider that the experience with beneficiaries pay from the US is a relevant precedent to rely on for introducing benefit-based charges into the TPM in New Zealand.

14.2.3 As the CEC 2019 Report states:

> *"It appears to me that the EA has borrowed the US concept and transplanted it to a fundamentally different NZ context, where it is neither appropriate nor beneficial."*[70]

14.2.4 Our research indicates that there are a number of fundamental differences between the US and New Zealand situation as captured in the following table:

United States	**New Zealand**
In the US, the benefits-based approach was introduced by the Federal Regulator to allocate the costs of certain "economic" (i.e. market-driven) transmission investments where the benefits of the investment flowed to more than one pricing zone (often state-sized or larger).	In NZ we do not have an interconnected multi-jurisdictional transmission system and so the issue of who should pay for particular transmission investments that benefit more than one jurisdiction simply does not arise.
Pricing zones in the US are very large. For example, the Joint Report notes that in the mid-continent transmission planning region: "*Each cost allocation zone is typically at least the size of a US state*". Within each pricing zone the costs are socialised using postage-stamp type methods.	When scale is considered, our current methodology is not that dissimilar to the US approach as the whole of NZ could fit within a single zone!
The purpose of the benefits-based approach in the US was to address the issue of under-investment where the states could not agree amongst themselves who should pay for investments benefiting multiple states.	In New Zealand we do not have an under-investment issue and indeed the original rationale for the reforms was to address concerns around over-investment. Nor do we have an issue in binding parties to pay for transmission assets. Under our system, the Commerce Commission is tasked with assessing the public benefits of transmission investments according to the tests set out in legislation. If an investment is approved, grid users are legally required to pay for it based on the allocation method approved by the Electricity Authority.
The Joint Report notes that acceptance of cost allocations has been enhanced in the US by processes which allow beneficiaries to have an input into long-term transmission plans and/or vote on whether investments are needed.	The Commerce Commission process requires consultation on major capex. However, it makes its decisions based on public not private benefits. Legislative change would be needed to allow beneficiaries to vote on whether investments are needed.
There is a process for challenging a cost allocation decision in the US where the cost allocation is not "*just and reasonable*". The Joint Report notes that: "*where challenge does arise, it tends to be where one or a very small number of parties were allocated all, or almost all, the costs of a high-value new investment*"	We are not aware of any plans from the Electricity Authority to allow grid users a formal right to challenge individual cost allocation decisions. The US experience confirms our expectation that where costs are allocated on a granular level, the small number of parties affected will

[70] CEC 2019 Report, p. 31

United States	New Zealand
	have strong incentives to dispute the process and decision making, including by political means.
The benefits-based approach has never been applied to existing assets in the US.	The Electricity Authority proposes to apply the benefits-based approach to selected existing assets.
In the US, other types of transmission investment such as investments to maintain reliability or achieve public policy objectives (e.g. to lower emissions) are generally allocated using simpler allocation methods, including postage-stamp type methods.	The current transmission pricing methodology in NZ, which uses a postage stamp allocation for the core grid, is similar to the pricing approaches that are generally used for reliability and public policy investments, and the approaches that are used to allocate costs within zones in the US.
Further, once the economic investments are allocated to particular states, those states can decide how to cascade down the allocated charges down to grid users and many use simple allocation methods (such as postage-stamp across large pricing zones).	NZ's current transmission pricing methodology aligns well with the approaches used by individual states to a "pass on" the cost of allocated economic market-driven investments within their states.

14.2.5 As demonstrated above, we consider that the US experience is largely irrelevant for the purposes of considering whether benefit-based charges should be adopted in New Zealand. This is because:

a. the beneficiaries in the US context relate to transmission companies, not the much more granular level of transmission customers proposed by the Authority; and

b. applying beneficiaries pays at a transmission company level (i.e. to set regulated revenue) is a very different proposition to beneficiaries pays at a transmission customer level (i.e. to set transmission prices). Transmission customers are much more fluid over time than a transmission company, which is an eternal feature of the market.

14.2.6 This is view is reinforced by the CEC 2019 Report:

> *"There are myriad Transcos in the US and it is not possible to generalize about how transmission pricing is undertaken. However, as I understand it, conventional transmission pricing methods are typically employed, such as postage stamping and peak charging. If the EA is to use the US BP regime to support its TPM proposals, the onus is on it to explain how these BP charges flow through to transmission customers and to explain how and why this is different to what it is proposing for transmission customers in NZ."*[71]

14.2.7 And by TLG 2019 Report:

> *"Some of the concepts proposed for New Zealand would be unique in their application in a market of the small size and level of competition as New Zealand. Often even the same concepts as may appear to be adopted in other markets have much broader application – such as across regions that may be many times bigger than New Zealand, meaning that the New Zealand implementation of the identified theories will be far more granular and detailed – and thus more susceptible to error, rent-seeking, or market power."*[72]

14.2.8 The US use of benefit-based charging that the Authority refers to relates to charges between grids, and as a result likely has not flushed out the many issues that may arise from implementation at a much more granular level.

[71] CEC 2019 Report, p. 33.
[72] TLG 2019 report, p. 2.

Part V

15 TPM Development Process

15.1 Code obligations

15.1.1 Under 12.81 of the Code, the Authority is obliged to consult on the process for the development and approval of the TPM. This process must be consistent with the Authority's statutory objective, most notably the efficient operation of the industry.

15.1.2 We have previously criticised the Authority for not providing sufficient details of the TPM development process and are therefore pleased that the Authority has set out more information about its proposed process in the 2019 Issues Paper.

15.2 Development timeframes

15.2.1 It is important that Transpower is allowed sufficient time to complete its development of the TPM.

15.2.2 We think this is a significant undertaking as the Authority's proposed charging structures is unique and involves a number of implementation issues, particularly with respect to how the benefits are identified, modelled and attributed.

15.2.3 In order to better understand the nature of this task we developed two case studies (discussed below).

15.3 Checkpoints

15.3.1 We do not think there is any need for the TPM to be developed in a secretive process.

15.3.2 Rather than have specific formal checkpoints in the process, we recommend that the Authority participates in Transpower's engagement processes as an observer. This is consistent with the efficient operation of the industry.

15.4 Stakeholder engagement

15.4.1 Consultation on the process is important because affected stakeholders need to have a meaningful opportunity to engage with Transpower on its design choices.

15.4.2 In order to get buy in we think it is going to be important that Transpower offer workshops and/or advisory groups on the core issues so that it can identify early any roadblocks, particularly in relation to modelling matters.

15.4.3 We proposed a TPM development process in our submission on the 2016 Issues Paper. We still think that would be a sound process but having reflected on the current TPM Guidelines wonder if it might be efficient to add in two additional step – namely consultation on emerging views and a specific consultation on modelling issues.

15.4.4 This will mean in effect that in addition to engagement via informal workshops and working groups, there would also be two formal rounds of consultation (including cross-submissions).

15.5 Case Studies on modelling sensitivities

15.5.1 As outlined earlier in our submission, we developed two case studies to help us better understand the practical application of benefit-based charging methodologies.

15.5.2 Case Study 1 considers the sensitivity of the vSPD modelling of the calculated benefits of the existing assets. It explores the sensitivity of the calculated benefits associated with the Wairakei Ring investment against a different counterfactual.

Case Study 1: Wairakei Ring investment

The approach adopted for Case Study 1 involved testing the sensitivity of the beneficiary assessment under an alternative counterfactual to that assumed by the Authority in determining the charges for the seven existing assets.

Specifically, we considered the impact on the calculated benefits for the Wairakei Ring investment had two geothermal generators not proceeded – Te Mihi and Ngatamariki – but rather additional generation investments were made in the transmission constrained UNI region in the absence of the Wairakei Ring transmission investment.

Figure 1 presents the sensitivity to the choice of counterfactual, showing the significant difference in the beneficiaries of the investment under the alternative counterfactual (in red), as compared with the results using the Authority's counterfactual (in blue).

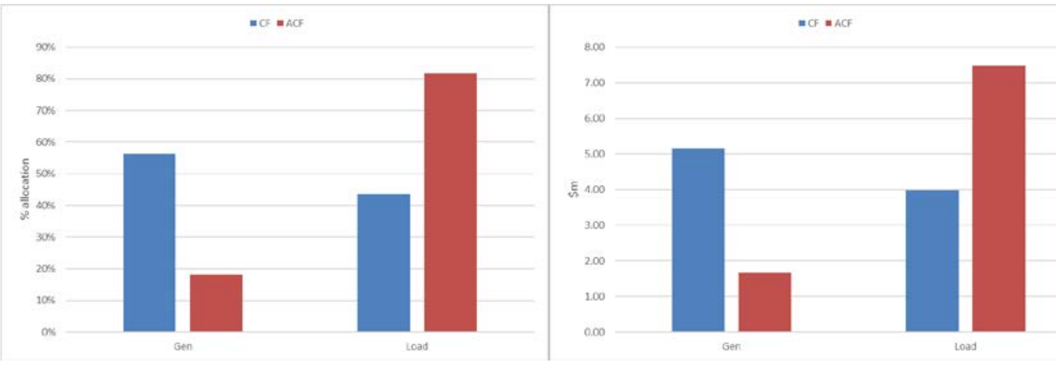


Figure 1: Comparison of benefits of Wairakei Link under different counterfactual assumptions

Under the alternative counterfactual, the Wairakei Ring upgrade facilitates investment in lower cost geothermal generation options leading to a reduction in spot market prices. Loads are the primary beneficiaries of these lower prices, with the majority of the existing generators facing lower spot prices and therefore not benefitting from the investment.

The new entrant geothermal generators benefit because in the absence of the transmission investment, the alternate counterfactual sensitivity assumes these additional geothermal generators would unlikely have proceeded (or deferred) as continuing with the generation investment in the absence of the transmission upgrade would imply lower spot prices thus reducing their profitability.

This case study demonstrates the sensitivity of the Authority's benefit calculation using the vSPD approach to the choices of counterfactual, with the alternate counterfactual assumptions resulting in different beneficiaries being identified, along with a different quantum of benefits/charges calculated for transmission customers.

See Appendix B for further detail of the supporting analysis for this case study.

15.5.3 Case Study 2 explores the sensitivity of benefits determinations to input assumption by comparing the extent to which actual outcomes compare with the assumptions that were used to justify the North Island Grid Upgrade (**NIGU**) project.

Case Study 2: NIGU Project

Case Study 2 explores the sensitivity of benefits determinations to input assumptions using the NIGU project as an example.

The approach involved using the reliability model previously developed by the Electricity Commission, to compare the expected reliability (as measured by expected unserved energy) in the absence of NIGU in the Upper North Island (**UNI**) using two cases:

a. Forecast case (based on load forecasts available at the time of the NIGU investment analysis)

b. Counterfactual case (using measured load) and including UNI generation retirement

The analysis period was 2016-18 to captured generator retirements.

Figure 1 presents the results of the analysis, illustrating the significant difference in expected unserved energy (**EUE**) in the UNI when using forecast vs actual peak demand growth, even with the retirement of a number of UNI generators.

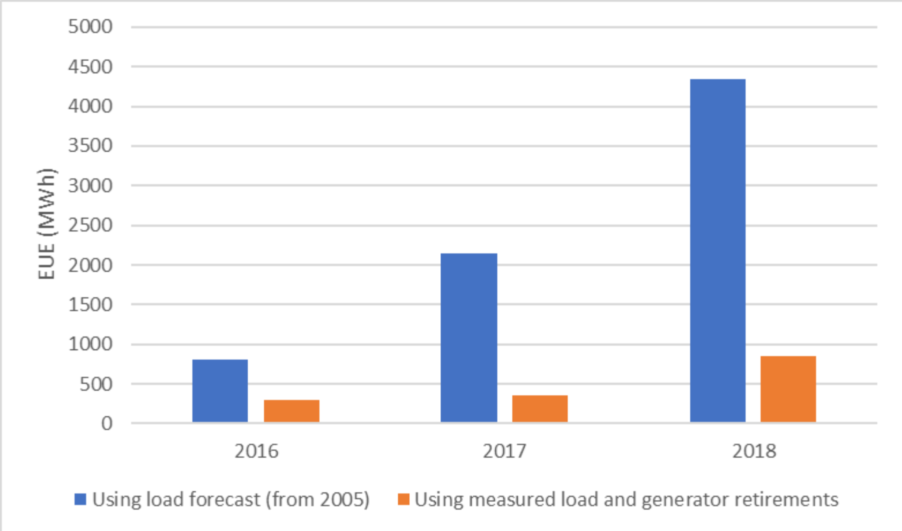


Figure 2: Difference in expected unserved energy

The results confirm our concerns that:

a. Actual conditions will almost always deviate from forecast conditions – in this case, the slowdown in UNI demand growth (following the global financial crisis) resulted in lower than expected benefits; and

b. Allocating charges based on these benefits could allocate costs to transmission customers that, at times, could deviate significantly from the benefits they actually derive from the transmission asset.

See Appendix B for further detail of the supporting analysis for this case study.

15.5.4 These two case studies identify that there will need to be a process and sufficient time for Transpower to express its emerging views on the core components of the modelling (including via stakeholder workshops) before formal engagement is commenced.

15.5.5 We think it is likely to take at least 18-24 months for Transpower to develop its thinking on all the new components of the TPM Guidelines and draft a full methodology for formal consultation.

16 Concluding remarks

16.1.1 The 2019 Issues Paper presents the findings of the Authority's TPM review and its Proposed TPM Guidelines.

16.1.2 Experts have advised that the Authority's proposal is a bold step as there is no overseas precedent for the entire removal of a peak demand charge or the application of a benefit-based charging at the transmission customer level.

16.1.3 There is doubt whether nodal prices will ever be sufficient to achieve the desired sector wide efficiency. There is however no doubt that this will not be able to be achieve in the current New Zealand market until:

a. There is a greater (and deeper) participation by the demand side;

b. Real time pricing has been implemented;

c. New tools to manage to transmission risk have been developed and introduced; and

d. New distribution pricing methodologies have been developed to pass on the price signals delivered by the new nodal pricing.

16.1.4 We also consider that the reliance on benefits-based charges is misplaced for all the reasons raised by experts and note that the preconditions for this type of pricing approach be effective include:

a. A consensus having been developed as to the nature of the various benefits provided by the transmission assets over time, and around how to value and attribute those benefits at a single point in time; and

b. A process having been developed and tested to get consensus from the parties expected to pay for transmission assets on the need for their construction and commissioning.

16.1.5 We are not at this point yet. This suggests that implementation of this proposal is not just a bold step, it is reckless and as such is inconsistent with the Authority's statutory obligations.

16.1.6 We also concerned that the implementation of this proposal could have immediate adverse implications for some of New Zealand's most vulnerable communities and on the willingness for investors to fund the necessary new investments to attain the Government's climate change objectives.

Appendix A: Responses to the Authority's questions

Q1 Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?

A.1.1. No. As we explain in the body of our submission (Chapter 7) the Authority has not undertaken a structured approach to its problem definition and options evaluation. Instead it describes potential sources of inefficiencies based on hypothetical case studies. There is very little quantification of the order of magnitude of these inefficiencies which means it is very difficult to develop a proportionate response.

A.1.2. The current interconnection charge provides a stable long-term price signal and has a method of allocation which is common overseas and has not been particularly contentious in New Zealand.

Q2. What are your overall views on the Authority's proposal for changes to the TPM guidelines?

A.2.1. We do not consider that the Authority has established the basis for changes of the magnitude proposed. Our reasons are set out in the body of our submission and in our Summary of Views.

Q3. 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?

A.3.1. No. Our experts have advised that the Authority's CBA does not provide a basis upon which to form a conclusion that the Proposed TPM Guidelines gives rise to net benefits, either in their own right or as compared to alternatives.

A.3.2. Further, the multiplicity of errors made by the Authority in the conceptualisation, formulisation and implementation of its analysis makes a simple 'fix' to these errors impractical within the timeframe provided by this consultation.

Q4. Do you have any comments on the matters covered in chapter 4 (consideration of the Authority's statutory objective)?

A.4.1. Yes. Please see our response in Chapters 4 and 8.3.

Q5. How long should Transpower have to complete its development of the TPM and why?

A.5.1. Please see our response in Chapter 14.

Q6. What checkpoints (if any) should the Authority set in the TPM development process?

A.6.1. Please see our response in Chapter 14.

Q7. How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?

A.7.1. Please see our response in Chapter 14.

Q8. In addition to the specific questions above, do you have any further comments on the matters covered in chapter 6?

A.8.1. No.

Q9. What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable?

A.9.1. As we do not support the Authority's proposals, we have not prioritised comments on the drafting.

Q10. 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?

A.10.1. No. The Proposed TPM Guidelines are not guidelines but a mix of principles, guidelines and pricing methodology, with the significant part constituting a default methodology which approval is needed to depart from. The Authority continues to usurp Transpower's role in relation to the TPM.

Q11. Should the current guidelines on connection charges be largely retained or are changes required?

A.11.1. Yes, subject to changes to address first mover disadvantage.

Q12. Should first-mover disadvantage be addressed in the TPM, and if so, how?

A.12.1. Yes, as this will avoid adverse competition outcomes. A contract solution would not address the situation where other expected connection customers do not materialise. Transpower should have full discretion as to how this issue can be addressed.

Q13. Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?

A.13.1. No. As the CEC 2019 Report advises:

> *"Charging based on a beneficiary-pays (BP) approach does not promote efficiency in user investment decisions, due to problems of dilution and opacity. Dilution, because the pricing signals provided by BP charges in this situation are likely to be a fraction of the long-run transmission cost. Opacity, because it will be impossible for most parties to predict these future BP charges in any case."*[73]

Q14. 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?

A.14.1. We do not consider that a benefit-based charge should apply to any pre-2019 investments. The costs for all past investments should instead be recovered through the residual charge.

[73] CEC 2019 Report, p. ii

Q15. Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?

A.15.1. In our view, the only possible candidate for benefits-based charge is the HVDC link. This is because a type of benefits-based charge is already in place.

Q16. How should the covered cost of the investment be defined?

A.16.1. We have not had sufficient time to consider this question.

Q17. 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?

A.17.1. The benefit that a customer receives from a transmission investment will vary over time. Ideally, the profile of recovery should follow the time profile of the benefits received by transmission customers to avoid distortions. However, this type of profile may not be practicable, including because it may not accord with the time profile of Transpower's MAR.

A.17.2. If the Authority proceeds with benefits-based charges, Transpower should be provided with discretion around the method that should be adopted for the recovery of investment costs over time.

Q18. Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?

A.18.1. A net load approach should be used to allocate benefits as it is likely to provide load customers with appropriate incentives with respect to future investment and because it better reflects the benefits that customers receive from grid-delivered electricity. Use of a gross load approach would reduce incentives for transmission customers to make investments that would defer or avoid future transmission investments.

A.18.2. In addition, it is simply not possible to measure gross load due to the difficulties of capturing behind the meter generation and battery storage. To attempt to somehow estimate gross load would inevitably result in inaccuracies and distortions, where some generation is captured and some isn't.

A.18.3. With regard to providing flexibility, it is important that that this does not inflate the risk of investments in solutions such as generation and demand response/load management that are aimed at reducing the need for transmission investment.

Q19. Should the guidelines distinguish between high-value and low-value investments?

A.19.1. Trustpower queries whether using a simple method would achieve the efficiencies that the Authority is hoping to achieve from benefits-based charging. In addition, the choice of threshold is an arbitrary one which could incentivising gaming, and also could mean that the allocation of similar investments that are either side of the investment threshold would be treated differently in terms of allocation and cost recovery thereby violating competitive neutrality (for example, between generators or between load).

A.19.2. If the Authority chooses to persist with benefit-based charges, Trustpower considers that all investments should be treated in the same manner, regardless of size. However, if the Authority does choose to distinguish between low-value and high-value investments, then the low value investments should be recovered through the residual charge.

Q20. 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

A.20.1. Refer to our response to Question 19.

Q21. 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?

A.21.1. Refer to our response to Question 19.

Q22. 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)?

A.22.1. We do not support the application of benefits-based charging to existing assets. Please also refer to our comments on the Authority's benefits determination on Chapter 12.

Q23. How should the costs of the investments that are not covered by the benefit-based charge be allocated?

A.23.1. The three large historic investments that the Authority does not propose to include in benefit-based charges should be recovered through the residual charge.

Q24. 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?

A.24.1. Yes. Trustpower considers that the wording "substantial and sustained changes in grid use" should be broadened to encompass situations where the forecast benefits are substantially different from the actual benefits. Otherwise the methodology will not be durable, however we acknowledge these reopeners will have implications for the efficiency of the charges.

Q25. Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?

A.25.1. We have not had sufficient time to consider these mechanics.

Q26. 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?

A.26.1. Yes. The guidelines should allow for reassignment from the benefits-based charge into the residual, this will have distributional impacts and implications for the efficiency of the charge.

Q27. Should the guidelines provide for a single residual charge or multiple residual charges?

A.27.1. We have not had time to consider this matter.

Q28. Should the residual charge be allocated based on a customer's historical electricity demand?

A.28.1. For the residual charge to be durable it must be capable of evolving with changing circumstances, rather than only in extreme circumstances. While we appreciate the trade-off is that there will be some distortions, we consider that this will be offset by the improvement to durability.

A.28.2. We note that the way in which distributors (and retailers) pass on the benefit-based charges would not be based on pre-2019 AMD – it is unlikely, for example, to be durable for a distributor to not charge anything to new connections, on the basis that their load did not contribute to pre-2019 AMD. What's more, distributors and retailers are not permitted to pass on a fixed charge to a large proportion of customers due to the Low Fixed Charge regulations. As a result, even if Transpower were to set residual charges on historic AMD on the basis that this is unavoidable, the practical reality is that the prices faced by retailers and their distributors would necessarily have some degree of unavoidability.

A.28.3. Solutions such as a rolling average over multiple years may assist with providing a cost allocation mechanism that evolves with changing circumstances, while lessening the likelihood to distortionary responses. These are matters for Transpower to resolve with its customers.

Q29. Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?

A.29.1. We note that Electricity Pricing Review investigated cost allocation in relation to distribution pricing. The Panel preferred an allocation based on MWh.

Q30. If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?

A.30.1. We have not comment at this time.

Q31. Should demand be measured using a net load or gross load approach for the allocation of the residual charge?

A.31.1. A net load approach should be taken for the allocation of the residual charge on the basis that:

A.31.2. Net load best reflects that burden that a customer places on the transmission network.

i It is not practicable to calculate the gross load, and an attempt to do so with result in differential treatment of some generation, and will in any case not be accurate

ii Differential treatment of measures to allocate benefit-based and residual charges may create unintended consequences – eg, over time as the proportion of Transpower's MAR recovered from residual charges reduces and the proportion recovered through benefit charges increases then under the Authority's proposal there will be a transition from allocation based on gross load to allocation based on net load. Also, to the extent that high and low value investments are treated differently with high value investments recovered through benefit-based charge and low-value investments recovered via the residual charge, there will be different allocation mechanisms.

Q32. 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?

A.32.1. All distributed generation should be treated equally to preserve competitive neutrality. As it is not possible to properly account for behind the meter consumption of generation and use of energy that has been stored in batteries, net load should be used as measured at the GXP.

Q33. Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?

A.33.1. Trustpower considers that the residual charge allocated based on net load as measured at the GXP, which implies that other data would not be required. We note that another allocation option would be nameplate capacity, but that would penalise low capacity/load factor installations.

Q34. Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?

A.34.1. No.

Q35. 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?

A.35.1. Yes. We consider that the residual charge allocations should be structured so as to adjust automatically to changing circumstances – for example, a rolling multi-year average MWh, rather than an allocation based on historic, pre-2019 data. If the residual charge is not structured to automatically adjust, Transpower would need to continually review the allocations.

Q36. Should the residual charge apply to both generation and load customers, or only to load customers?

A.36.1. The residual charge should be applied only to load customers, as this would be the least distortionary way in which to recover costs, as is identified by the Authority. If the residual charge were to apply to generation, then this would effectively mean that although Transpower bills a fixed charge to generators that is allocated based on historic demand, the framework of the wholesale market means that this would then be recovered through a MWh charge based on current energy use. Given the Authority's desire not to incentivise avoidance behaviour, recovery via load will be likely to be less distortionary than via load and generation.

Q37. Are the proposed guidelines relating to adjustments appropriate?

A.37.1. Yes.

Q38. 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?

A.38.1. The prudent discount should relate to the period over which the avoidance could occur. For example, if a prudent discount is provided on the basis that the customer is able to use an alternative energy source (such as gas) but the price of that alternative increases then the discount should be revised. At the very least, prudent discount arrangements should be subject to a periodic review, say, a 10 period.

Q39. 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?

A.39.1. The Authority's proposed price cap is incredibly complex and would be very limited in its application. The proposed capping mechanism:

i enables a rise of up to 40%[74] in the transmission component of a customer's total electricity bills before applying – which means in most cases the price cap would provide very little protection against substantive reallocations in transmission charges; and

ii applies to any initial price shock associated with the application of the benefits-based charges to the seven historic assets, and will be no longer applicable if it does not apply in any one year – which means in almost all cases, the proposed price cap would be no longer applicable prior when the costs of new assets are allocated via the benefit-based charge.

A.39.2. The potential for price shocks to arise every time a new transmission investment occurs is one of the most undesirable features of the proposed benefits-based charge.

A.39.3. The Authority's view that fully exposing customers to the costs of new transmission assets they are deemed to benefit from will promote more efficient decision making, fails to consider the implications of ongoing price shocks. Particularly with respect to achieving the Government's policy objectives around greater electrification, regional development and improving energy affordability.

A.39.4. Relatedly we do not consider that the Authority has adequately provided for a transition to the proposed new future state, despite recognising there are interrelated changes that will have potential implications for the overall success of implementing the proposed arrangements.

A.39.5. It is important that any significant change to the transmission pricing structures would be introduced incrementally, in a way that avoids prices shocks, is sensitive to the impact on vulnerable communities and limits the potential for unintentional consequences.

A.39.6. In our view a gradual transition over a number of years will be required and the final revised transmission pricing structures need to better insulate customers from price shocks (both at commencement and on an ongoing basis). We note that our proposed variations enable a much simpler form of transition to protect against price shocks.

Q40. Should the price cap be specified as a percentage of electricity bills or in some other way?

A.40.1. Refer to answer to Q39

Q41. Should the price cap apply only to load customer, or to generators as well?

A.41.1. In principle a price cap should be applied equally to both load customers and generators. However as suggested above our proposed variations would not require this matter to be explicitly considered.

Q42. How should the price cap be funded?

A.42.1. As discussed above, Trustpower does not consider that pre-2019 investments should be funded through a benefit-based charge. As a result, we consider that the price cap should be funded

[74] Transmission costs are only 10% of a customer's total electricity bill. The proposed price cap of 3.5% of total electricity bills would represent around a 30-40% cap on the transmission component of a customer's total electricity bill.

through residual charges, noting that if a benefit-charge is not applied to pre-2019 investments, the cost of the price cap will be substantially lower than under the Authority's proposal.

Q43. Are the proposed additional components appropriate? If not, what changes should be made?

A.43.1. Additional component F relates to the way in which opex is recovered. Ideally opex relating to specific connection assets, would be recovered from charges to the transmission customer that is paying for the connection investment costs.

A.43.2. This would be expected to result in more efficient pricing of connection charges, and could potentially result in more engagement by at least large transmission customers in Transpower's operations and maintenance expenditure practices. Whether this is practicable depends of whether Transpower records opex against each connection asset. The way in which the additional opex component is framed does not seem unreasonable.

A.43.3. We consider that the Authority's proposal to include kVAr charges as an optional additional component, over which Transpower would have discretion, is reasonable. As the Authority notes, a number of distributors levy a kVAr charge in relation to large connections.

A.43.4. The application of a kVAr charge to grid connected load will improve competitive neutrality with regard to the choice of industrial customers with regard to being grid connected or connected to a distribution network.

A.43.5. More generally, applying a kVAr charge would improve efficiency by incentivising those customers with poor load factors to invest in reactive support equipment, rather than imposing costs on other customers.

Q44. Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?

A.44.1. Please see Chapter 10.

Q45. Should the peak charge be applied only where the grid would otherwise be congested?

A.45.1. We are of the view that a surgical peak change (i.e., a granular charge that only applied where the grid is congested) would be administratively burdensome to Transpower and not provide a stable signal for investment to come forward to avoid peak usage.

A.45.2. Congestion will always be a feature of networks due to growth. In order for non-transmission options to arise, advance signals are required.

Q46. 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?

A.46.1. Please see Chapter 10.

Q47. Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core proposal?

A.47.1. No. We do not support retroactive application of benefit-based charges to past investments.

Q48. In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?

A.48.1. No, other than those in the body of our submission.

Q49. Do you have any comments on the matters covered in this Appendix C? {Material change in circumstances test}

A.49.1. Yes. Refer to Chapter 5.

Q50. Do you agree that the analysis presented in chapter of the second issues paper (elaboration of the decision-making and economic (DME) framework) remains appropriate?

A.50.1. No. Refer to Chapter 6.

Q51. Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?

A.51.1. No. Refer to Chapter 6.

Q52. Do you agree with the conclusions of Appendix D [Elaboration of the DME framework]?

A.52.1. No. Refer to Chapter 6.

Q53. Do you have any comments on the matters covered in Appendix D?

A.53.1. Yes. Refer to Chapter 6.

Q54. Do you agree with the conclusions we draw from Transpower's report *The role of peak pricing for transmission?*

A.54.1. We do not agree with the Authority's conclusions noting that nodal prices are unlikely to work in practice as anticipated by the Authority. Refer to Chapter 11 and the associated expert reports.

Q55. Do you agree that nodal prices enhance by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?

A.55.1. No. See response to Q54.

Q56. 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?

A.56.1. No. Refer to Chapters 10- 12.

Q57. Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficient restrain grid use to capacity?

A.57.1. No. Refer to Chapter 11.

Q58. Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?

A.58.1. No. Refer to Chapters 10 and 11.

Q59. Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?

A.59.1. No. Refer to Chapter 7.

Q60. Do you have any comments on the matters covered in this appendix E?

A.60.1. No.

Q61. Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?

A.61.1. We agree that residual loss and constraint excess from an investment should be assigned to those who pay charges in relation to the investment.

Q62. 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?

A.62.1. We appreciate the Authority providing notice that it intends to make a change to the ACOT regime in the future.

A.62.2. However, we have not had sufficient time to consider the details of this code change as we have prioritised responding to the broader policy issues associated with the Authority's proposal.

Q63. 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?

A.63.1. We do not support this proposal as we think it will usurp the current material change of circumstances threshold in the Code and because there is insufficient clarity about how the Authority's decision-making criteria might change the TPM. Thus, this proposed Code change will harm rather than promote investor certainty with adverse effects on the long-term interests of consumers.

A.63.2. We note that under the Code, Transpower can propose amendments at any time within the published guidelines. This in combination with guidelines which are not excessively prescriptive will enable any workability issues to be addressed.

Q64. In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F (EA's response to criticisms of its TPM reform proposal)?

A.64.1. No.

Q65. Do you have any comments on the matters covered in this appendix G [Response to some criticisms]?

A.65.1. We have not had sufficient time to respond to the Authority's comments.

Q66. When commenting on details of the modelling using vSPD to propose the benefit allocation to recent major investments and the impacts modelling, please consider responding to these questions:

a) Over what period should we undertake the vSPD modelling?

A.66.1. Our view is that four years is an insufficient period to capture a range of system conditions. Transmission investments are modelled over multi decades so a historical four year assessment is grossly inadequate. Please note that in the body of our submission we outline our broader concerns about the use of a historical period (2014/15 – 2017/18), as opposed to being the forward-looking approach that Transpower adopts for assessing grid investments, along with the sensitivity of the modelling to input assumptions. The net result is that benefits calculated by the Authority for the seven historic investments are not a robust reflection of the allocation and quantum of future benefits and are unlikely to be durable.

b) Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either case, what is the appropriate level of the VPO?

A.66.2. In the event that the Authority pursues the application of benefit charges to past investments, the use of a variable VPO seems more realistic. We however note the sensitivity on the distribution of benefits in adopting this approach.

c) 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.

A.66.3. Trustpower notes that it has been allocated approximately $100,000 of benefit charges in relation to the Cobb hydro generation plant, which has been embedded since early 2015 due to the sale by Transpower to Network Tasman of the 66kV transmission assets that the Cobb power station is connected to. Cobb was grid connected for the first seven months of the period modelled by the Authority: July 2014 – January 2015 inclusive.

A.66.4. We request that, if the Authority continues with vSPD modelling based on the specified four-year period, that Cobb power station's generation for the period July 2014 to January 2015 be removed from the calculation of Trustpower's generation of benefit charges. The amount of Cobb's generation during the seven-month period at issue should be netted off STK0331/STK0661. Making these changes would accord with the Authority's proposal that one of the conditions under which changes can be made to charge allocations is where a transmission customer changes its point of connection. This is the situation for the Cobb where the point of connection has changed from COB0661 to STK0661.

d) 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.

A.66.5. If the Authority continues to use the current modelling period for assessing the benefits of existing assets, the generation volumes relating to the Cobb hydro station which are used to calculate the benefit charge should be removed to account for the fact that its POC has changed and it is no longer grid connected.

Q67. 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).

A.67.1. Not at this time.

Appendix B: Challenges with modelling transmission investment benefits

Case Study 1 - Wairakei Ring

Background

B1. The Wairakei Ring (**WRK Ring**) Project was approved by the Electricity Commission (**EC**) in Feb 2009.

B2. In its proposal to the EC, Transpower stated the following:

> *"...upgrading the Wairakei Ring assists in facilitating competition and security of supply by removing constraints in an area where significant renewable generation is proposed by a number of parties"*

B3. As part of the Authority's TPM beneficiary calculation for the WRK Ring, the Authority conducted a counterfactual solve with the WRK Ring investment removed from the grid, resulting in a reduction in transmission capacity in the Wairakei region. This counterfactual solve is used as the basis to determine how much participants prices and quantities change when the investment is re-instated.

B4. The vSPD results from this counterfactual solve with the WRK Ring investment removed indicates significantly lower prices in the Wairakei region due to binding transmission constraints. As an example:

i Wairakei market node (WRK2201) price reduces by 25%

ii Te Mihi market node (THI2201) price reduces by 23%

B5. The Authority's counterfactual assumes that new geothermal generation investments occurring after the WRK Ring upgrade approval would have proceeded unaffected had the WRK Ring upgrade not gone ahead even through these new generators (and some existing generators) would experience significantly lower wholesale prices for their generation due to binding transmission constraints

B6. Two such geothermal generation investments made in the Wairakei region after the approval of the WRK Ring project were:

i Te Mihi : 166MW commissioned in 2014

ii Ngatamariki: 82MW commissioned in 2013

Spot price comparison

B7. Figure B1 compares the spot price under both the Authority's factual (F) and counterfactual (CF) cases.

B8. The counterfactual prices (average over the four-year modelled period) illustrates the reduction in prices received by generators at nodes in the Wairakei Ring, assuming new geothermal projects (Te Mihi and Ngatamariki) proceed even though the WRK Ring upgrade does not.

B9. Average price reductions of 23-25% are observed in the WRK ring under the Authority's CF case, resulting in reduced revenue to all generators (existing and new) within the WRK Ring region.

B10. There is also significant price separation between the WRK Ring and the result of the system is also assumed to persist in the Authority's counterfactual case.

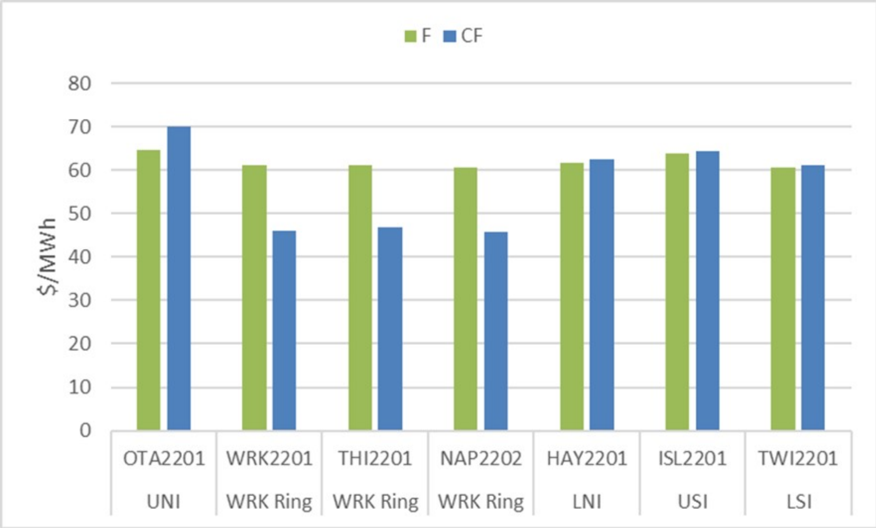


Figure B1: Average spot prices for the Authority's factual (F) and counterfactual (CF) cases at different market nodes

The Authority's beneficiary assessment

B11. Based on its counterfactual assumptions, the Authority's benefit assessment calculates a larger proportion of the WRK Ring upgrade costs for generators who are deemed to benefit more than loads.

B12. This is based on the assumption that generators face much lower prices without the WRK Ring investment due to additional geothermal generation investment in the constrained Wairakei region (as shown in Figure B1).

B13. The WRK Ring investment results in increased spot prices for these generators and thus larger benefits as illustrated in Figure B2.

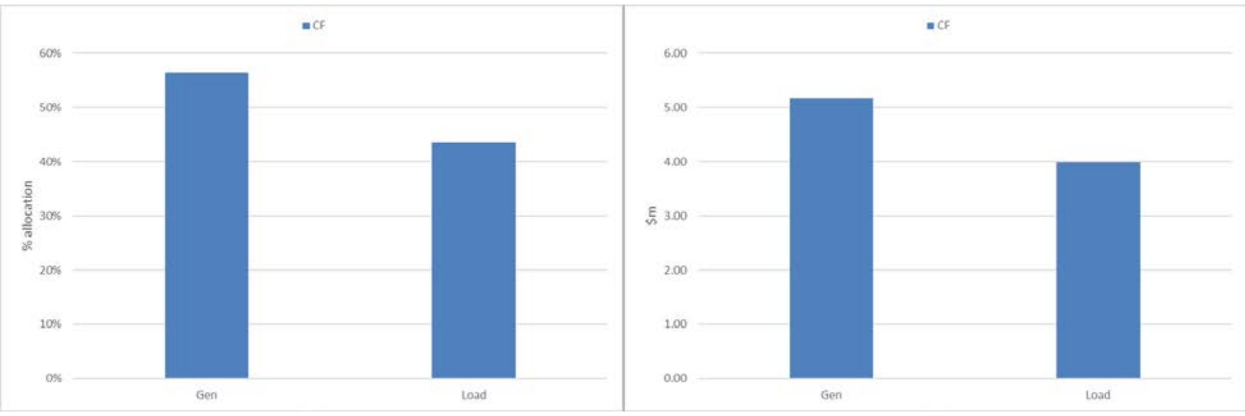


Figure B2: Share of benefits allocated to both generators and load for WRK Ring upgrade (% allocation and $m)

Alternate counterfactual (ACF)

B14. We tested the sensitivity of the Authority's WRK Ring beneficiary assessment with respect to its input assumptions.

B15. Specifically, we considered the impact on calculated benefits had two new geothermal generators not proceeded had the WRK ring upgrade not been considered:

i Te Mihi : 166MW[75]

[75] Introduction of Te Mihi resulted in ~45MW reduction in output from Wairakei geothermal station. So Te Mihi resulted in a net increase of ~121MW of overall generation capacity. This was taken into account in the modelling.

ii Ngatamariki: 82MW

B16. We assumed that in lieu of the above geothermal investments, additional generation investments would have been made in the transmission-constrained UNI region which is represented through an increase in the capacity of the Authority's virtual price offer at the OTA2201 market node.

B17. The vSPD market model was used to recalculate the market dispatch for the ACF scenario. We also applied the netting rules as described by the Authority in its 2019 Issues Paper to estimate vSPD net benefits.

B18. The results in the following Figure B3 compares the benefits calculated under the Authority's counterfactual (**CF**) and this ACF sensitivity.

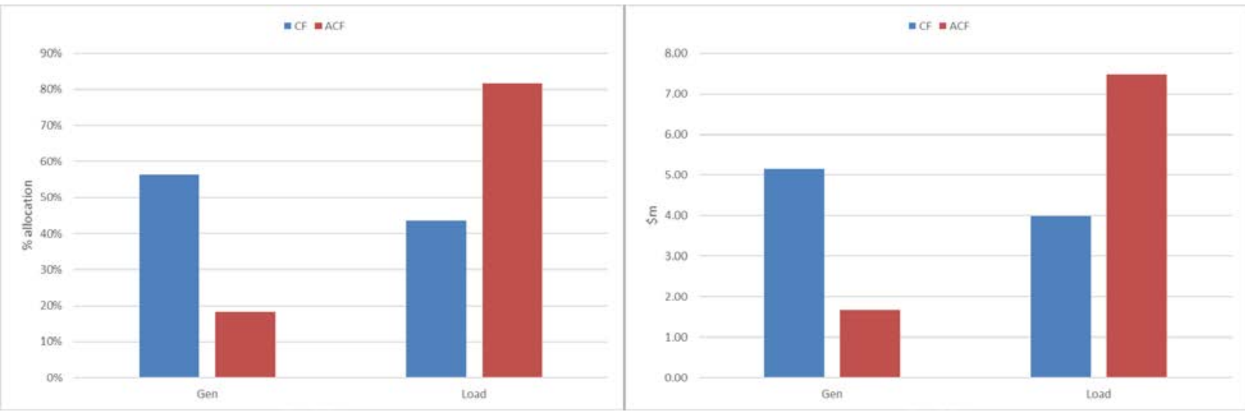


Figure B3: Comparison of benefits under different counterfactual assumptions

Summary of results of alternative WRK Ring counterfactual

B19. Under the ACF sensitivity, loads are calculated as the major beneficiaries of the WRK Ring investment.

B20. Under this sensitivity, the WRK Ring upgrade facilitates investment in lower cost geothermal generation options, reducing spot market prices. Loads are the primary beneficiaries of these lower prices due to these lower cost generation resources entering the electricity market. The majority of the existing generators would face lower spot prices (than would otherwise be the case) and thus are considered not be benefit from the investment. Figure B4 provides a comparison of the spot prices calculated under the alternate counterfactual sensitivity.

B21. The new entrant geothermal generators are also beneficiaries under this sensitivity's assumptions as it facilitates their generation investment - was it not for the transmission investment, their generation investment would be replaced by other higher cost generation in the system. Due to the transmission investment their generation investment is more profitable by receiving a higher spot price for its generation.

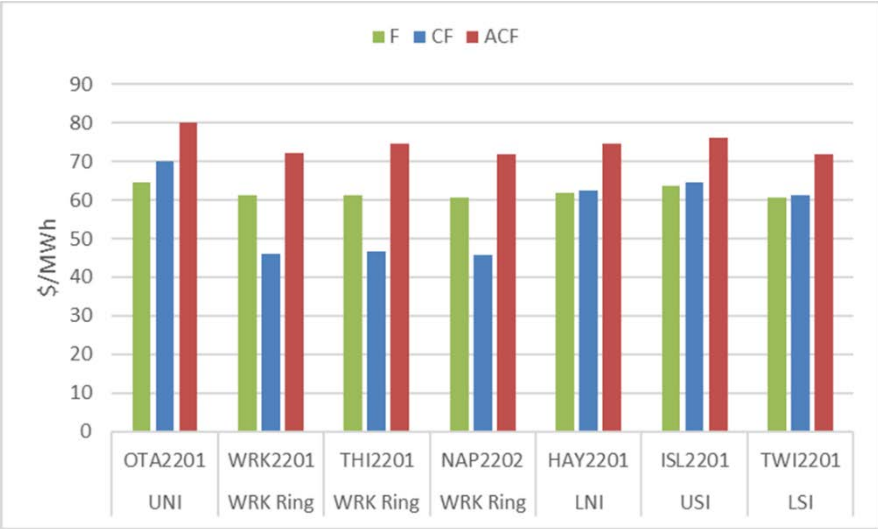


Figure B4: Comparison of average market node spot prices under factual and different counterfactual assumptions

Changes in Allocations

B22. The Authority's CF, allocates costs to existing and new generators injecting into the Wairakei ring, whereas the ACF sensitivity identifies the new geothermal investments (post WRK Ring upgrade) as the major beneficiaries. The results are presented in Figure B5.

B23. Under the alternate counterfactual, loads in both islands benefit from the lower spot prices brought about by the investment in lower cost geothermal generation. This is presented in Figure B6.

Conclusions

B24. Case Study 1 used the WRK Ring investment to consider the potential sensitivity of the benefit-based charges for the seven historical investments as proposed by the Authority as part of its 2019 Issues Paper.

B25. This analysis shows that the benefits calculated by the Authority using the vSPD approach are sensitive to the choices of input modelling assumptions with alternate counterfactual assumptions impacting the identification of beneficiaries and quantum of benefits (and consequently charges) calculated for transmission customers.

B26. Given this sensitivity in the identification and quantum of benefits to the choice of input assumptions used by the Authority, we do not consider the vSPD approach proposed by the Authority as appropriate to "lock-in" transmission charges for customers for the seven historical investments.

B27. Furthermore, we consider that the vSPD assessment used by the Authority on the seven historical assessment deviates significantly from the investment modelling Transpower would undertake for future investments. The Authority's vSPD approach considers only situations that have occurred over the 4-year historical time period (2014/15-2017/18) exploring system states observed during this period whereas a forward-looking assessment (as used for an investment) would need to consider a much longer time horizon (20+ years) and wider range of system states (considering entry and exit of generators, loads and technology developments). Given the long-life nature of transmission assets such an assessment becomes necessary to compare the "whole-of-life" impact of different investment options. Given our observation on the sensitivity of the benefits calculated by the Authority to its input modelling assumptions, we believe these benefits could vary quite significantly if assessed using an approach more aligned with the investment process.

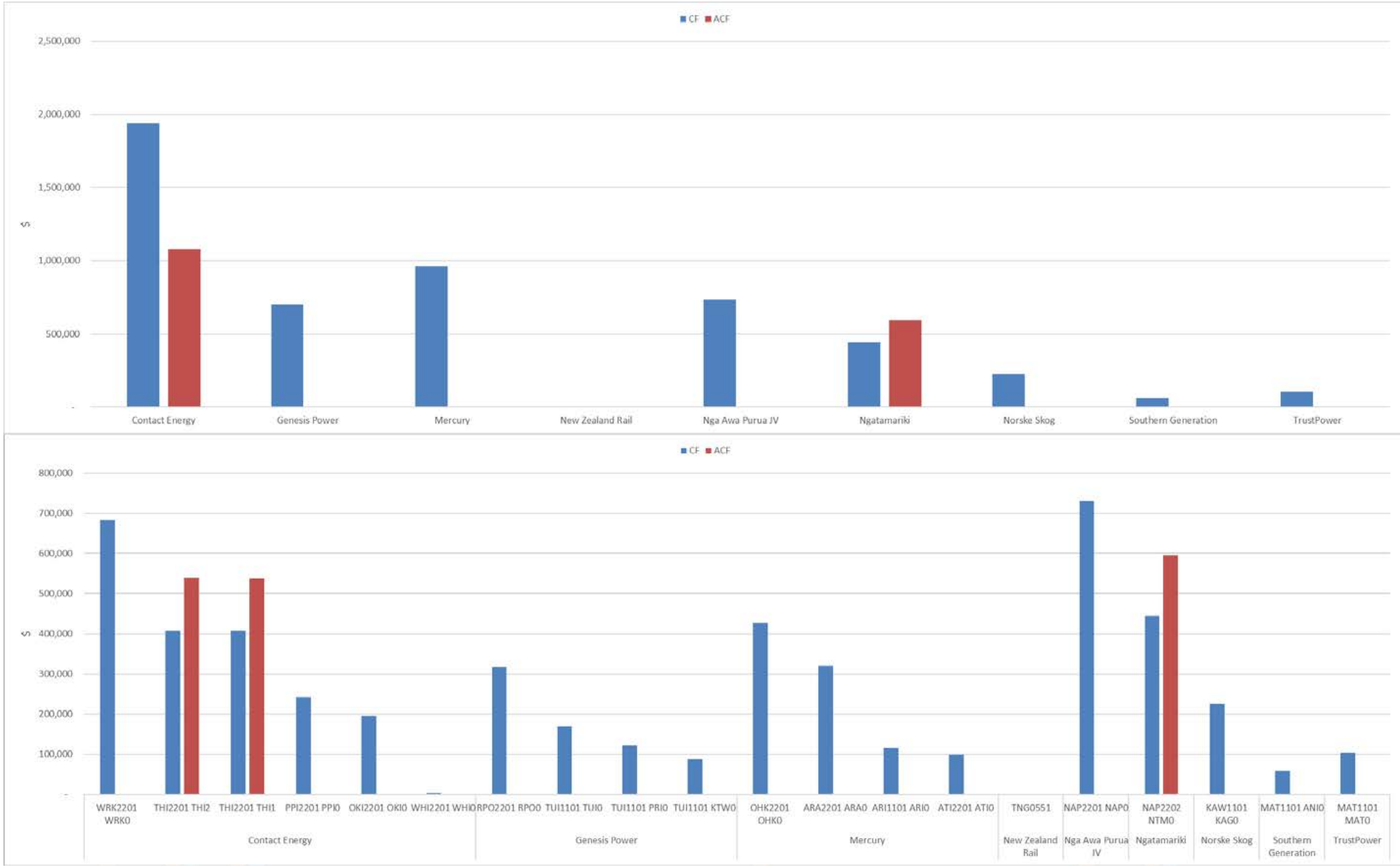


Figure B5: Comparison of WRK Ring cost allocation to generator customers and generator customers by market node under the Authority's CF and the ACF sensitivity

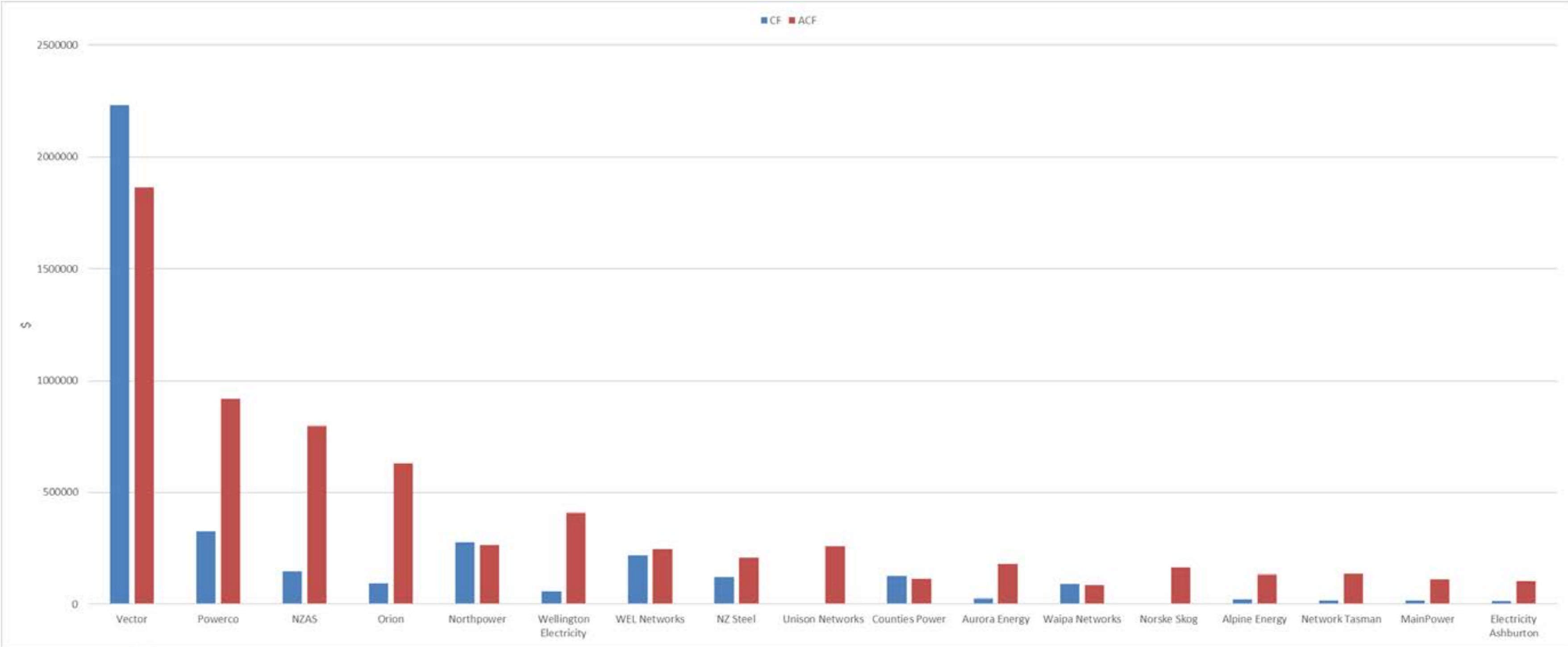


Figure B6: WRK Ring cost allocation to load customers under the Authority's CF and the ACF sensitivity (plot shows costs of at least $100k p.a.)

Case Study 2 - North Island Grid Upgrade

Overview

B28. The NIGU project was a reliability investment to improve security of supply into the UNI using the forecasted load growth. The expected benefits of this project was increased reliability to the UNI by reducing the likelihood of load curtailment in the region.

B29. This assessment looks at the sensitivity of project benefits to input assumptions using the NIGU project as a case study.

B30. This analysis is not an attempt to replicate or critique the analysis used for the NIGU investment but rather is intended to illustrate the variations in the modelled outputs and the issues this could cause when trying to forecast the benefits of a transmission investment under the Authority's proposed benefits-based approach.

Approach

B31. The NIGU project was a reliability investment to improve security of supply into the upper North Island under the forecasted load growth.

B32. The approach involved comparing the expected reliability (as measured by expected unserved energy) in the UNI using two alternate cases:

i Forecast case – using UNI load forecasts available at the time of the NIGU investment analysis).

ii Counterfactual case - using measured load and including UNI generation retirement (with the benefit of hindsight).

B33. The analysis period was 2016 to 2018 to capture the effects of the UNI generator retirements.

B34. For this analysis, a reliability model developed by the EC was used to compare the EUE.

EC reliability model

B35. The EC reliability model was developed to assess the UNI EUE under different generation outage combinations.

B36. Input data into the EC model includes:

i UNI import capability under different generator outage combinations - This provides an indication of the maximum UNI load that can be supplied via the generation and transmission system under different generator outage combinations. The reliability model uses a polynomial approximation to look up the UNI import capability for a given generator outage combination state. We will refer to this as the UNI load-serving capability.

ii UNI load - A half-hourly load probability curve (**LPC**) was developed by the EC for 3 seasons of each forecast year (summer, winter and extreme summer). The LPC indicates the probability that a randomly chosen half-hour will have an average load above a certain level.

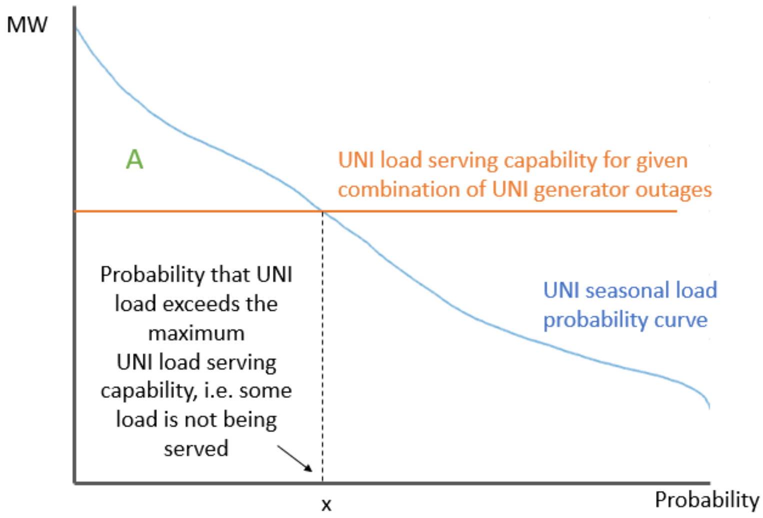
iii Generator forced outage rates - Probability of failure of a generator (based on seasonal forced outage rates) as calculated by the EC.

B37. For a given combination of UNI generator outages within a season of a simulated year, the:

i UNI load capability is calculated;

ii LPC is compared to the UNI load capability; and then iii Seasonal UE is the integral of the LPC above the UNI load capability multiplied by the number of hours of the year represented by the seasonal LPC.

The seasonal EUE is calculated as the average UE calculated using multiple random draws of UNI generator outages combinations. In this assessment 10,000 random outage combinations were used. Finally, the seasonal EUE for each year is added to provide an estimate of the annual UNI EUE. Figure B7 provides an illustration of the EUE calculation in the EC reliability model.



Steps to calculate the EUE

1. $UE_{s,r}$ = Area A_r x hours represent by the season (s) LPC
2. $EUE_s = \Sigma_r UE_{s,r}$/number of random draws (r)
3. $EUE = EUE_{winter} + EUE_{summer} + EUE_{extreme\ summer}$

Where r = random draw of UNI generator outage combinations and s = modelled seasons {winter, summer and extreme summer}

Figure B7: Illustration of EUE calculation in the EC reliability model

Forecast vs actual peak load in the UNI

B38. The forecast peak load is based on the maximum annual load as provided in the UNI Load LPC developed by the EC.

B39. The actual peak demand is based on the Reconciliation Manager load available from the Electricity Authority's Electricity Market Interface (**EMI**).

B40. A comparison of forecast vs actual peak load in the UNI reveals that the growth in the UNI peak demand is well below the forecasted growth. This is reflected in Figure B8.

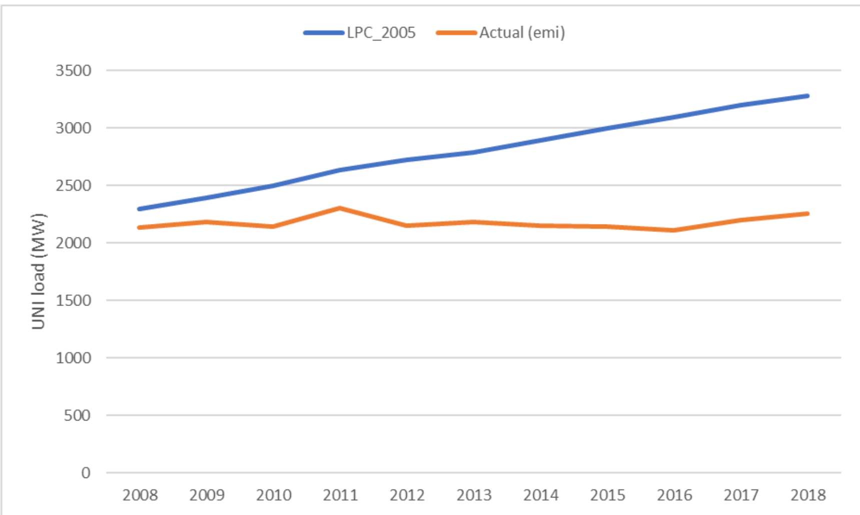


Figure B8: Forecast peak load vs actual peak load in the UNI

UNI load serving capability

B41. Figure B9 shows the UNI load serving capability under different generator outage combinations without the NIGU investment. These values were calculated by the EC using power flow simulations

B42. A polynomial fit is calculated and used by the reliability model to estimate the maximum load that can be supplied in the UNI under different generator outage combinations.

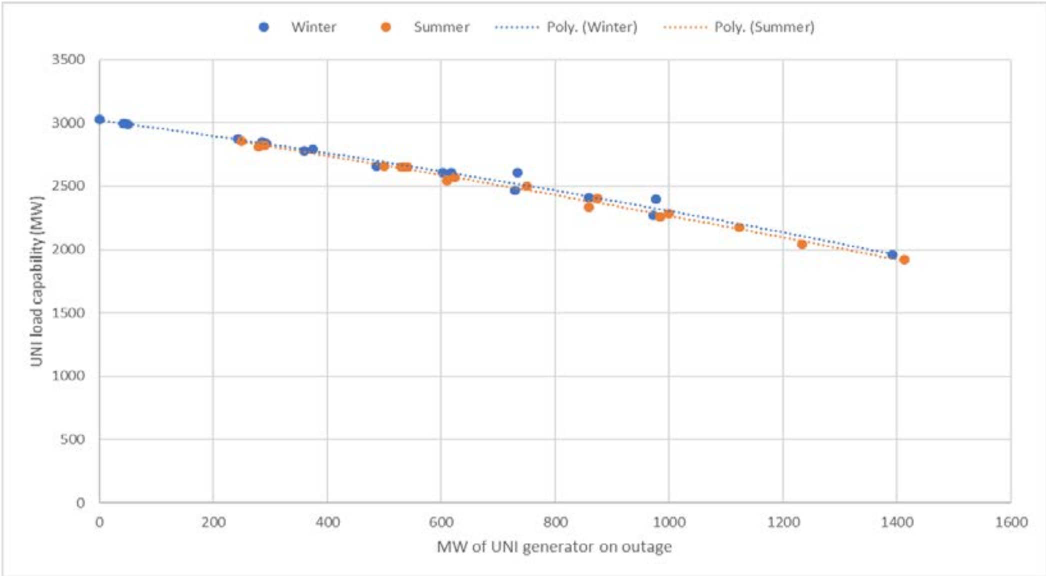


Figure B9: UNI import capability

Difference in EUE

B43. Figure B10 compares the forecast case against the counterfactual case as was described in paragraph B32 and demonstrates the sensitivity in expected future benefits to modelling inputs.

B44. The large reduction in EUE (UNI benefits) in the actual scenario is due to actual load being much lower than forecast. This is even with the retirement of UNI generators.

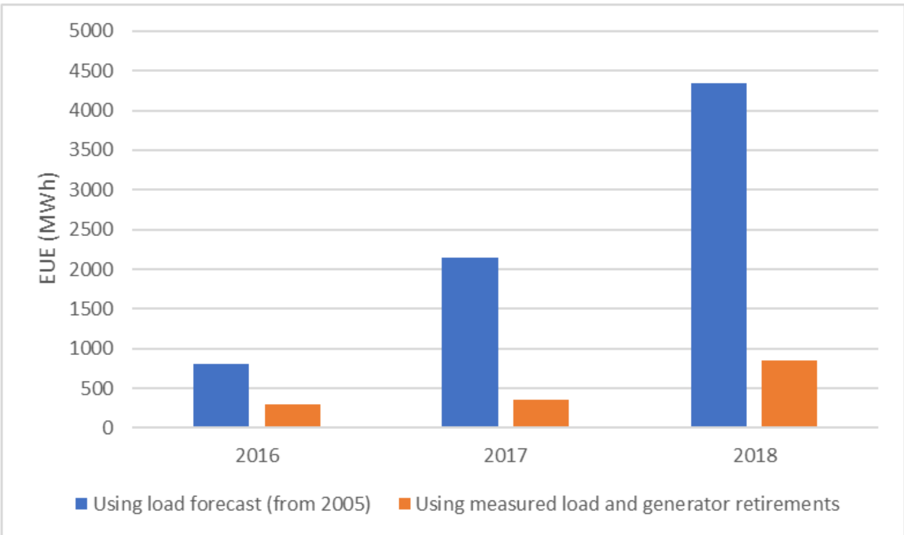


Figure B10: Difference in expected unserved energy

Conclusions

B45. Case Study 2 illustrates, with the benefit of hindsight, some of the potential issues with trying to forecast the benefits of a transmission asset. In particular how forecast benefits could vary (potentially quite significantly) when actual conditions deviate from forecasts.

B46. The results confirm our previously stated concerns that:

i Actual conditions will almost always deviate from forecast conditions – in this case, the slowdown in UNI demand growth (following the global financial crisis) resulted in lower than expected benefits; and

ii Allocating charges based on these benefits could levy costs to transmission customers that, at times, could deviate significantly from the benefits they actually derive from the transmission asset.

Appendix C: vSPD modelling issues

Summary

C1. The Authority used the vSPD market dispatch model together with post-process netting rules to determine the proposed annual benefits-based charges for the seven historical investments in its 2019 Issues Paper

C2. Having reviewed the approach undertaken by the Authority, we have identified the following findings:

i. **The vSPD approach is sensitive to input assumptions**: In the Authority's vSPD assessment, a number of input assumptions are required to estimate benefits. These assumptions relate to market behaviour, generation entry/exit/deferral, network constraints, demand and the modelling horizon. We tested a number of these assumptions and observed large variations in the benefits-based charges based on the setting of these assumptions.

ii. **The vSPD approach deviates from a traditional grid investment assessment:** The Authority's approach (using vSPD) calculates benefit over a historical period (2014/15-2017/18) instead of being a forward-looking assessment. As a result, the assessment only captures the "states of the world" that are presented in the historical analysis and by definition would not capture alternate system conditions that could potentially prevail in the future. In contrast, Transpower's assessment of grid investments would typically consider the potential impacts of a transmission investment considering a range of potential future scenarios over several decades[76]. Given the observed sensitivity in the Authority's approach, we would expect significant variation in the benefits calculated by the Authority if exposed to a forward-looking, scenario-based analysis over a much longer time horizon.

iii. **There are a number of other practical modelling implementation issues that could potentially affect the benefits calculated by the Authority**. These relate to:

- Treatment of positive and negative benefits across years (i.e. calculating total net benefit across the modelling horizon)
- Treatment of infeasibilities
- Treatment of adjustments at Kaikohe
- Application of the netting procedure

C3. Given the observed sensitivity of the calculated benefits to choice of input assumptions, the limited modelling horizon and scenarios considered for the assessment and some of the practical issues in implementation, we are not convinced the calculated benefits for the seven historical transmission investments are a robust reflection of the allocation and quantum of future benefits.

Overview of the approach used by the Authority

C4. The Authority used an assessment of a 4-year historical period to estimate benefits (and consequently the benefit-based charges) for the 2021/22 pricing year. For the seven historical investments assessed by the Authority, the vSPD model was used to calculate benefits for:

i. Factual scenario – schedules and prices based on the final pricing market solves

[76] The Capex Input Methodology requires Transpower to complete the Investment Test for major capital projects. The Investment Test is an economic cost-benefit analysis that considers a range of future scenarios that account for issues such as technology development, demand growth, entry and exit of generation.

ii. Counterfactual scenario – modelled outcomes with the asset removed from service

C5. Demand was reduced at Kaikohe and Kawerau to account for additional geothermal generation investment by 2022.

C6. The following assumptions were made in the vSPD modelling:

i. Historical bids/offers were used under both the factual and counterfactual scenarios

ii. Historical demand was used under both the factual and counterfactual scenarios

iii. No further system contingencies/outage scenarios were considered

iv. A virtual price offer was introduced with assumed price and quantity to represent additional investment in the counterfactual scenario

v. No reserves were modelled for the Authority's proposed assessment of HVDC beneficiaries

vi. Periods with infeasibilities were omitted

C7. Netting rules were applied to convert vSPD-calculated benefits to net benefits. Benefits were calculated by node and allocated to customers for each of the seven historical investments[77].

Calculated benefits are sensitive to input assumptions

C8. In the Authority's vSPD assessment, a number of input assumptions are required in its modelling of the beneficiary-based charges for historical investments. These include assumptions around market behaviour, generation entry/exit/deferral, network constraints, demand, modelling horizon.

C9. We have tested the sensitivity of the calculated benefits to some of these assumptions to better understand the stability of the underlying benefit determination. In particular, we considered the impact of the fixed vs variable price for the Authority's virtual price offer and the impact of sensitivities in the counterfactual assumptions.

Impact of the VPO

C10. The Authority introduces the virtual price offer (VPO) as a generic supply resource to represent alternate developments (demand response or generation) that may have occurred had a transmission investment not proceeded (i.e. the counterfactual solve).

C11. Two options are considered for the price of the VPO in the Authority's assessment:

i. Fixed at $500/MWh

ii. Variable price set at 20% above the base case (factual) nodal price (preferred by the Authority)

C12. While we note the Authority's preference for the variable VPO, we observe the sensitivity on the distribution of benefits in making such a decision.

C13. The higher fixed $500/MWh VPO price increases the proportion of benefit-based charges to North Island (NI) distributors (significantly for some) and reduces proportion of charges to generators and South Island (SI) load, as can be seen from Figure C1.

[77] The UNI reactive support and NIGU were investments considered together. The same benefit allocation was applied to both these historic investments.

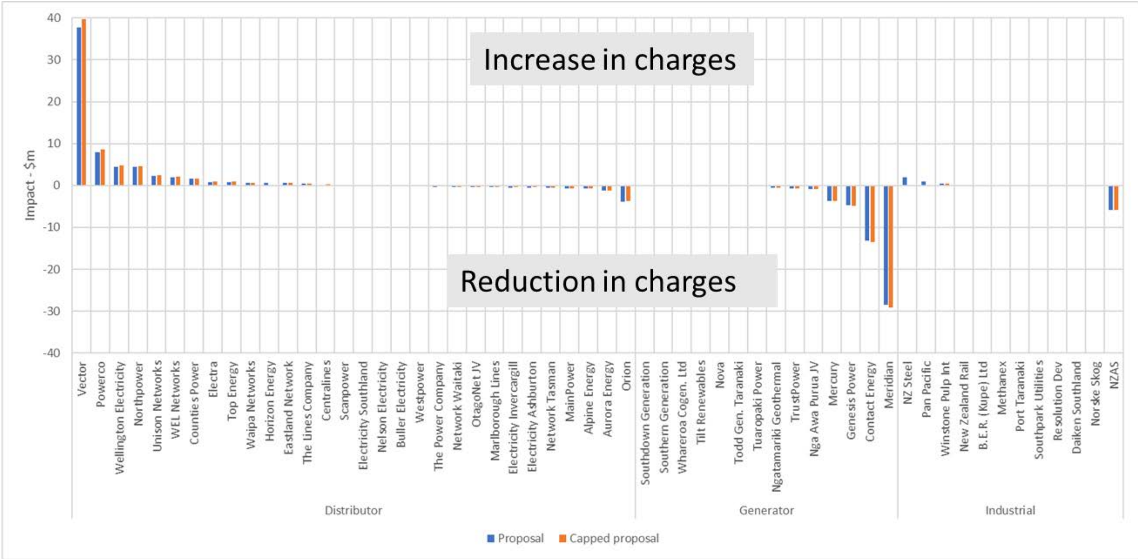


Figure C1: Impact of VPO price ($500/MWh (fixed) vs variable price) on indicative transmission charges for 2021/22

C14. Using the higher (fixed) VPO price, Vector's beneficiary-based charge increases by $37m (before cap) and $39m (after the cap) is applied.

C15. Beneficiary-based charges for SI customers reduce under a higher (fixed) VPO price sensitivity. As an example, Meridian's beneficiary-based charges could reduce by ~$29m under the higher VPO price sensitivity.

C16. Figure C2 below, demonstrates that changing the VPO price can significantly change the allocation of the NIGU benefits with upper North Island distributors picking up a much larger proportion of these charges.

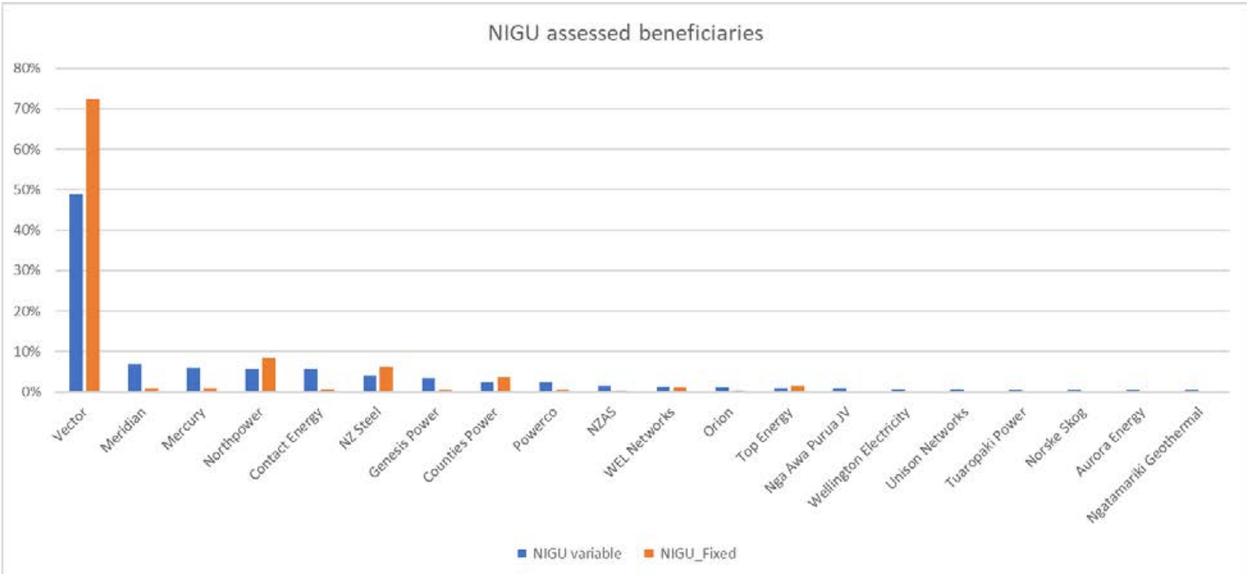


Figure C2: Impacts of changes in VPO price ($500/MWh(fixed) vs variable price) on NIGU assessed beneficiaries

Impact of low prices

C17. While the Authority introduced the VPO as a proxy for a market adjustment to high prices in its vSPD modelling of counterfactual scenarios, no assumptions were made in regards to how the market might adjust if prices reduced well below observed spot market prices.

C18. As an example, the Authority's Wairakei Ring assessment assumes, in the absence of the Wairakei Ring upgrade, geothermal generators continue to invest and participants continue to offer in as observed in the current market, even though doing so exacerbates the transmission constraint in the Wairakei Ring thus significantly reducing spot prices to generators in the Wairakei Ring region. This amounts to irrational generator behaviour.

C19. Conducting an alternative, more rational counterfactual sensitivity assuming in the absence of the Wairakei Ring upgrade, investment in additional generation resources[78] in the upper North Island (to relieve the transmission constraint in the Wairakei Ring) with less investment in new geothermal resources[79] in the Wairakei Ring has a large impact on the calculated benefits and beneficiaries. The details of this analysis are discussed in Appendix B.

Impact of alternate counterfactual assumptions

C20. There is a significant reduction in spot prices calculated in the Wairakei Ring in the Authority's assumed counterfactual (CF) versus the factual (F) case, as shown in Figure B4 in Appendix B. However, in a more rational alternate counterfactual (ACF), spot prices show a general increase, particularly within the Wairakei Ring, as discussed in Appendix B.

C21. Appendix B also showed that there is a significant change in the proportion of benefits (and charges) to generators and loads depending on counterfactual assumptions.

Low counterfactual prices in the no HVDC scenario

C22. The impact of the Authority's assumption of unchanged market offers under both the factual and counterfactual scenarios can also be seen in its assessment of the HVDC.

C23. The following figure shows a price duration curve at the Benmore market node (BEN2201) under the Authority's modelled factual and counterfactual scenarios for its identification of HVDC beneficiaries.

C24. Under the counterfactual, prices in the SI reduce to below $1/MWh for 60% of the 4 year modelling period with an average price of $48/MWh. The quantum of benefit assigned to SI generators is based on this counterfactual assumption of these very low SI prices in the absence of the HVDC.

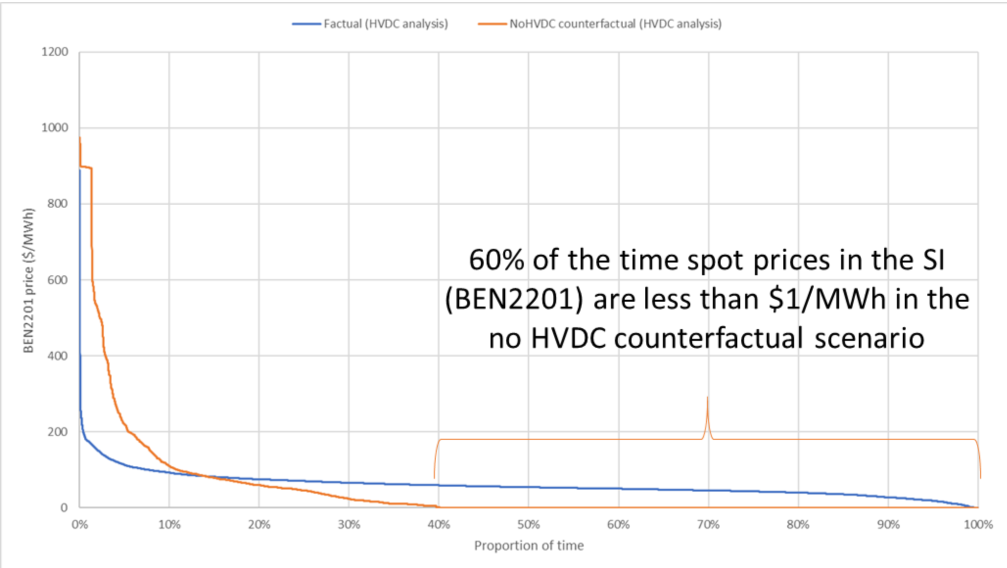


Figure C3: Benmore (BEN2201) price duration curve for the Authority's factual and counterfactual scenarios used for the HVDC analysis

[78] Modelled as an increase in the capacity of the Authority's VPO
[79] Te Mihi and Ngatamariki were two generators built after the Wairakei Ring approval

C25. To understand the potential impact on prices with no HVDC, we did a comparison of the following:

i. Average of the Authority's simulated Benmore price (in the counterfactual scenario with no HVDC investment); and

ii. Average of the Authority's simulated Benmore price for the HVDC factual scenario (i.e. with the HVDC investment in place) but for trading periods with and without flow on the HVDC. Note: Zero HVDC flow periods indicate that only generation within the island can be used to supply that island low. These situations can occur in the factual scenario due to faults or maintenance outage of the HVDC.

C26. While this analysis does not take into account longer term dynamic effects of investment, operational and demand adjustments to a "no HVDC" scenario, it does provide an illustration of market adjustments to changing network state (in this case with no inter-island transfer on the HVDC link). We identified 461 such trading periods in the 4-year modelling results of the factual scenario (with no reserve modelling) with zero flows on the HVDC.

C27. The following Figure C4 shows the results of this analysis. The Benmore average price in the HVDC factual simulation but with no HVDC flow (grey bar) is actually slightly greater than the average price when there is non-zero HVDC flow. This indicates little-to-no effect on the observed average SI price when there was flow on the HVDC vs when there was no HVDC flow.

C28. This indicates that consideration of market adjustments is an important part of the assessment in the Authority's counterfactual that would impact some of the beneficiary allocations calculated for the HVDC (Wairakei Ring and potentially the other historical investments being considered). Again, it appears the Authority has not allowed for dynamic market behaviour in its counterfactual modelling.

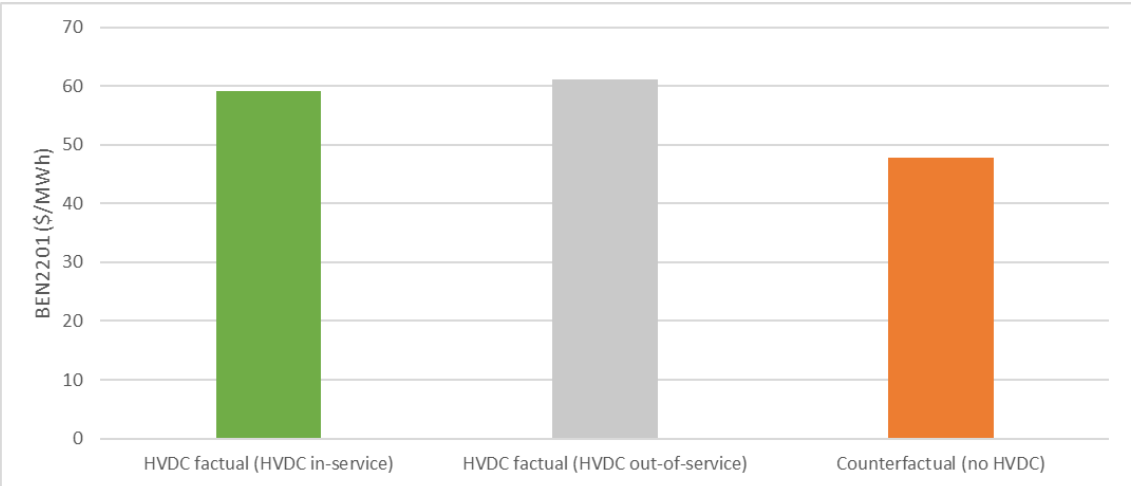


Figure C5: Average Benmore price from the Authority's proposed factual (zero and non-zero HVDC flow) and counterfactual vSPD scenarios ("no HVDC") used for HVDC benefit calculations

Other observations on the vSPD modelling

C29. The Authority's historical assessment does not capture the range of potential future impacts and the changes in the impact of transmission investments over the life of the transmission asset. A forward-looking assessment is normally used when assessing grid investments to capture the impact (and range of impact) of a transmission investment considering potential changes in and uncertainty of:

i. Demand – including the effects of demand growth drivers such as industrial electrification, EV uptake and impact of removing the RCPD charge;

ii. Technology – for example, changes in PV, wind and storage costs; and

iii. Supply alternatives – such as potential generation entry, exit and demand response.

C30. In using the vSPD model with only 4 years historical data, the Authority's modelling only captures the outages (planned and unplanned) that have already existed in the past which are then replayed through the factual and counterfactual analysis.

C31. While this provides an exploration of the potential situations that have occurred, without explicitly modelling other potential planned and unplanned outages, the analysis will not be able to capture the full impact of transmission investments and the potential beneficiaries of these investments.

C32. Based on our observations of the variability of assessed benefits and beneficiaries to changes in input data into the vSPD modelling, we would expect the above modelling updates to alter (potentially significantly) the assessed benefits and beneficiaries.

C33. Thus we are not convinced the Authority's historical vSPD analysis undertaken for the seven historical transmission investments captures the full range of potential future beneficiaries and benefits expected over the lifetime of these investments.

Impact of considering total benefit across the modelling horizon

C34. To account for changes in assessed benefits under different market conditions, the total or cumulative benefit over the modelling horizon should ideally be considered.

C35. The approach undertaken by the Authority considers the total net benefits within a year. But nodes, whose total net benefit within a year is negative, are not included when calculating the annual average of the multi-year modelling horizon.

C36. Under the Authority's approach this implies that a customer incurring large disbenefits (negative benefits) from the presence of a transmission investment for majority of the years in the selected modelling horizon, would still pick up a benefit-based charge for that asset if in one of the years it incurred a positive benefit. The fact that the customer, on balance, incurs large disbenefits due to the transmission investment is irrelevant to the Authority's benefit calculation.

C37. We tested an alternate assumption where both positive and negative benefits are considered equally over the multi-year modelling horizon. We refer to this as the total net benefit, as illustrated in the green-shaded text box below.

C38. In the Figure C6 below, each blue-shaded block represents the total annual net benefit calculated at the end of each year for a generator or load node. The grey-shaded text box describes the Authority's calculation of the annual average benefit. Only the annual net benefit that is greater than zero is included in the Authority's calculation.

Year 1: B1>0	Year 2: B2<0	Year 3: B3>0	Year 4: B4<0

EA annual average benefit = (B1 + B3)/4

Annual average *total* net benefit = (B1 + B2 + B3 + B4)/4
Annual average *total* net benefit is set to zero if the above calculation is less than zero.

Figure C6: Comparison of the Authority's proposed annual average benefit calculation versus alternative

C39. Figure C7 shows the estimated impact (difference) when considering the total net benefit across the modelling horizon versus the approach undertaken by the Authority. Positive indicated the increase in charges for a transmission customer when the alternate assumption of considering total net benefit across the modelling horizon is used.

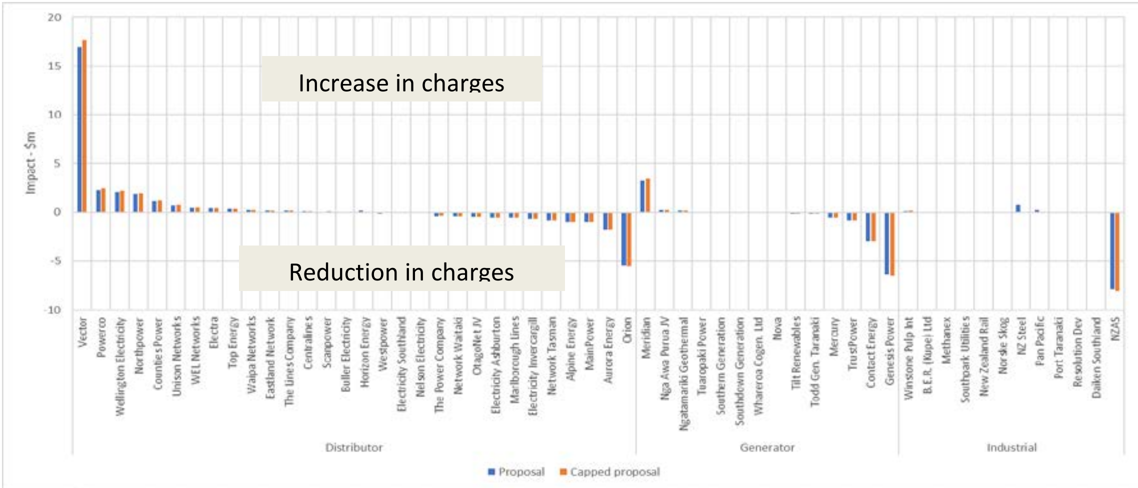


Figure C7: Estimated impact on indicative transmission charges for 2021/22 when considering total net benefits across the modelling horizon versus the Authority's proposed approach

C40. When calculating benefits as the total net benefit across the modelling horizon we observe quite significant changes in the calculated benefits with some NI distributors incurring greater charges.

C41. Meridian also incurs a greater charge due to it being assigned a greater proportion of the HVDC charge. This is due to the netting of positive and negative benefits reducing other customers total net benefit more than Meridian. As an example, for the HVDC, disbenefits calculated for SI loads during normal and wet years offset positive benefits calculated during dry years thus reducing their total net benefit from the HVDC investment. Under the Authority's calculation the SI loads pick up a greater share of the HVDC (thus reducing Meridian's share) as only the years where their total annual benefit is positive was included in the annual average benefit calculation.

Benefits sensitive to deficit generation infeasibilities

C42. Deficit generation infeasibilities occurs when there is insufficient supply to meet the demand at a node or a group of nodes. This could be because of localised or wider capacity shortages and could reflect short-term constraints that need to be addressed.

C43. The Authority has indicated it has removed these infeasible periods. However, if the counterfactual case is capturing the modelled system without the relevant grid investment in place, we consider these infeasible periods could be providing valuable information on constraints within the system (albeit transient and only occurring under certain network configurations). By removing these price signals (during infeasibility periods) the modelling will be distorting some of the benefits being provided by a transmission investment.

C44. Using the Authority's results for the No NIGU counterfactual (which includes the variable VPO), we identified the periods with deficit generation infeasibilities[80]. Pricing the infeasible energy at $10,000/MWh indicates a potential additional benefit in the UNI of ~$60m across the four historical years (~$15m/yr). Including this impact increases the contribution of UNI loads to the NIGU investment by 4% (58%-60%).

[80] 141 trading periods with deficit generation in the UNI identified over the 4 year modelling period.

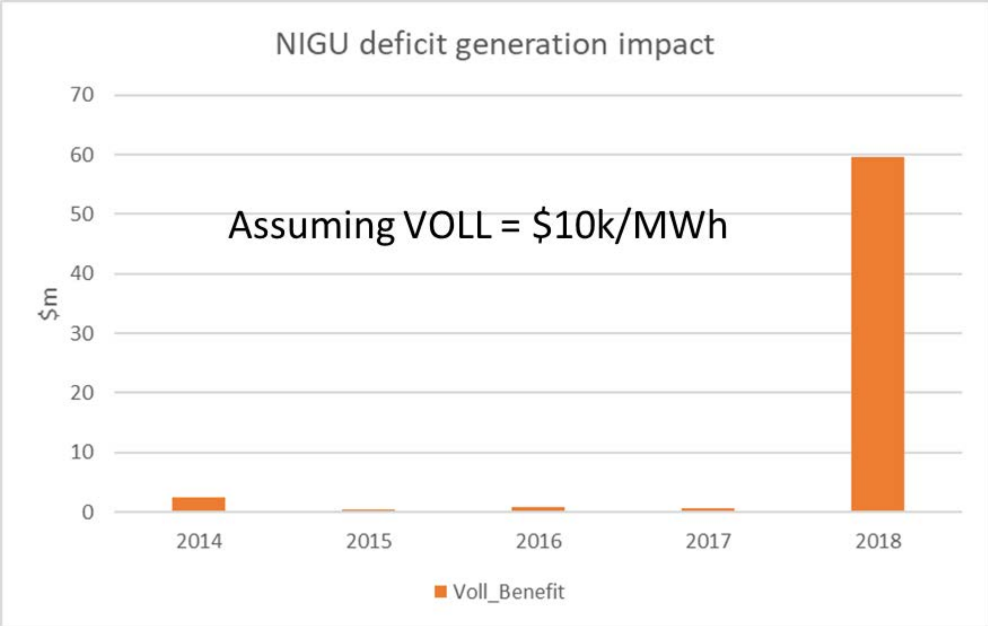


Figure C8: NIGU deficit generation impact

Other issues noted with the benefit calculations – Kaikohe adjustment

C45. The Authority has indicated a change was required to the benefits calculated at Kaikohe due to the initial assumption the additional generation at Ngawha would be embedded but is now expected to be grid connected.

C46. In recalculating the benefits for Kaikohe, load benefits for the following two historical investments were not included:

i. BPE-HAY

ii. LSI reliability

C47. We observed benefits for the above two investments at the adjacent market node Maungatapere (MPE1101) and used this as a proxy for the investments that would also benefit Kaikohe (KOE1101). Including the above adjustments would have some impact on the benefit allocation.

Netting procedure observations

C48. The Authority is proposing a netting procedure to account for embedded, partially embedded and co-generation generation.

C49. We agree that a more consistent treatment of embedded generation is required as the treatment of embedded generation within the vSPD model is not consistent (e.g. some embedded generators have offers and others represented through reduction in demand).

C50. However, in analysing the netting procedures provided by the Authority in its published calculation spreadsheet, we noticed different netting approaches used for different netting groups. These different approaches can potentially result in some difference in the calculated benefits. Further details are provided in Figure C8 below.

	Netting requirements for net vSPD (netting groups)
1	Net generation and load at ABY0111 with TIM0111_ALPE
2	Net generation at ASB0661 HBK0 with load at ASB0661
3	Net generation at CYD0331 with load at CML0331
4	Net generation at DOB0331 with load at DOB0331
5	Net generation at GLN0332 GLN0 with load at GLN0331 (not load at GLN0332 as not needed for full netting and Counties is a partial customer of GLN0332)
6	Net KUM0661 and KUM0661 KUM0 against GYM0661
7	Net LTN0331 generation against LTN0331 load
8	Net NMA0331 generation against NMA0331 load
9	Net NSY0331 against NSY0331 PAE0
10	Net ONG0331 generation against ONG0331 load
11	Net STK0661 COB0, against STK0331, but not Nelson electricity (also STK0331) as different customer
12	Net TGA0331 KMI0 generation against TGA0331 load
13	Net TWH0331 and HAM0111 against TWH0331 TRC1
14	Net WIL0331 generation with load at WIL0331 and TKR0331
15	Net WRK0331 RKA0 and WRK0331 TAA0 with loads at WRK0331 and ROT0331
16	Net: HWA1101 PTA1 with HWA1101 PTA2, HWA1101 PTA3, HWA1102 WAA1, HWA0331, SFD0331 (not HWA1102 WAA0) Patea DG to net against Powerco
17	Net: HWB0331 with HWB0331 WPI0 and BWK (netting Berwick against "Aurora"), because it is DG
18	Net KAW0111 and EDG0331_HEDL (an offset for Horizon)
19	Net KAW0112, KAW0112 DLS0, KAW0112 ONU0 KAW0113 and KAW0113 DLS1 (Norske Skog) add KAW1101 (load and gen)
20	Net KIN0112 and KIN0112 KIN0 with KIN0111, KIN0113
21	Net ROT1101 WHE0 with load ROT0111 and load at OWH0111

Figure C8: Netting groups defined by the Authority to calculate its NET.vSPD results

C51. The Authority has applied the following netting procedure for 16 of the 21 netting groups shown in Figure C8 above.

i. Subtract generation from load at the same node

ii. Aggregate any residual generation from (i) within the netting group

iii. Subtract generation calculated in (ii) from remaining load at nodes within the netting group starting in descending order of load magnitude

C52. The above generic approach is not applied to the following netting groups:

i. Netting group 3:

a. CYD0331 generation is not subtracted from load at the same node but subtracted from the CML0331 load.

b. The load CYD0331 load is not adjusted

ii. Netting group 15:

a. WRK0331 RKA0 generation is initially subtracted from ROT0331 load and not WRK0331 load.

b. WRK0331 TAA0 generation and any residual generation from (a) is subtracted from the WRK0331 load.

iii. Netting group 18:

a. KAW0111 generation is not subtracted from load at the same node but EDG0331 load.

b. KAW0111 load is not adjusted.

iv. Netting group 20:

a. Generation at KIN0112 is not subtracted from load at the same node but from load at KIN0111.

b. KIN0112 load is not adjusted.

v. Netting group 21:

a. ROT1101 WHE0 generation is subtracted from OWH0111 load.

b. Residual generation from (a) is subtracted from ROT0111 load (Load at ROT0111 is greater than load at OWH0111)

Appendix D: HoustonKemp 2019 Report

"*Review of the cost benefit and options analysis of the EA's proposed TPM Guidelines*", a report by HoustonKemp, September 2019

Appendix E: CEC 2019 Report

"*Review of the Electricity Authority's TPM Third Issues Paper*", a report by Creative Energy Consulting Pty Ltd, September 2019.

Appendix F: The Culy Report

"*Battery Analysis*", a report by John Culy Consulting, 24 September 2019.

Appendix G: TLG 2019 Report

"Comments on the Transmission Pricing Methodology", a report by The Lantau Group, September 2019.

Review of the cost benefit and options analysis of the EA's proposed TPM guidelines

A report for Trustpower

30 September 2019

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Executive summary

On 30 July 2019, the Electricity Authority (EA) released an issues paper, which sets out its proposal to change the guidelines that Transpower must follow in developing the transmission pricing methodology (TPM). The TPM establishes how Transpower's regulated revenues will be recovered from users of the transmission system.

This issues paper is the third proposal that the EA has put forward to change the TPM guidelines. The EA's most recent proposal contains most of the elements set out in its second issues paper and proposal and would amend the guidelines to require Transpower to make fundamental changes to the TPM, including:

- removal of the existing interconnection charge and high voltage direct current (HVDC) charge;
- introduction of two new charges, consisting of:
  - a 'benefit-based' charge on load and generation; and
  - a residual charge on load.

TPM guidelines are not technically part of the Code, but the TPM that is developed to comply with them is. The EA has taken the view that, given this process may give rise to changes in the Code, it would be helpful to develop a cost benefit analysis and an assessment of alternatives as part of the development of the TPM guidelines. This approach is also consistent with the EA's obligation to follow processes that are consistent with the efficient operation of the industry.

A cost benefit analysis of the EA's proposal should take into account all costs that it causes – whether these arise in the transmission sector or elsewhere in the electricity industry. By way of example, the Commerce Commission's approach to reviewing the efficiency of capital expenditure proposed by Transpower explicitly has regard to 'the capital cost of efficiently meeting demand by means of modelled projects', where these include all non-transmission related assets potentially affected by the option being evaluated.

The EA's cost benefit analysis estimates present value net benefits, measured against a status quo in which the existing TPM continues to apply, of $2,711 million (ranging from $201 million to $6,383 million) in connection with its proposal.

By way of comparison, net benefits of $213.3 million were estimated for the substantially similar proposal published by the EA in 2016. This analysis was shown to be affected by serious errors which called into question its robustness. These findings led to a delay in the EA's development of the TPM guidelines.

Against this backdrop it might be expected that the EA would seek to put forward a robust analysis of the costs and benefits of its latest proposal. Our assessment shows that this is not the case. The EA's cost benefit analysis:

- contains errors in its conceptual framework that cause it to overestimate benefits and underestimate costs and which, when corrected, show the proposal to give rise to net costs;
- contains further errors of assumption and approach that render its results unreliable and not fit for its intended purpose;
- does not reflect a best practice approach because it does not consider alternative options and incorrectly specifies potential outcomes under the status quo;
- assumes the efficacy of its proposal but does not show this to be the case; and
- does not support reform to the TPM guidelines in the near term since, even on its own estimates, the EA does not establish substantial net benefits arising from its proposal over the next decade.

In our view, these errors are just as serious, and in some respects more acute, than the errors in the 2016 cost benefit analysis that caused the EA to delay the development of the TPM guidelines. In its current form, the EA's cost benefit and options analysis does not provide a basis upon which to form a conclusion that its proposal gives rise to net benefits, either in its own right or as compared to alternatives.

The multiplicity of errors made by the EA in the conceptualisation, formulisation and implementation of its analysis makes a simple 'fix' to these errors impracticable within the timeframe provided by this consultation.

The cost benefit analysis contains errors in its conceptual framework

The EA's cost benefit analysis is affected by errors that cause it to overstate the benefits and understate the costs of its proposal. The EA's conceptual framework for estimating the benefits under its grid use model, which accounts for the large majority of the net benefits, contains errors such that it:

- overestimates the benefits of its proposal by including a transfer from producers to consumers, whereas it should only include the change in deadweight loss; and
- underestimates the costs of its proposal by excluding the impact of higher peak demand on generation and distribution costs, while capturing only some of the impact on transmission costs.

Transfers between two groups are not benefits to society and do not improve economic efficiency. However, the EA's estimate of benefits associated with greater use of the grid are dominated by transfers from generators to consumers associated with lower nodal prices. The vast majority – about 98 per cent – of the change in consumer surplus that the EA estimates is a transfer, rather than a benefit.

Most of the benefits that the EA claims for its proposal arise from higher peak demand due to the removal of the RCPD charge. However, higher peak demand imposes costs on the electricity industry, since it requires greater capacity to be built in the generation, transmission and distribution sectors. The EA's cost benefit analysis underestimates these costs because it:

- assumes incorrectly that the costs of building new generation capacity are incorporated in its analysis;
- ignores altogether the costs of building new distribution capacity; and
- underestimates the costs of building new transmission capacity by averaging across scenarios with lower cost outcomes (while not having regard to those scenarios in its estimates of benefits).

The costs of investing in new generation are costs to society to which the EA must have regard in assessing the costs and benefits of its proposal, regardless of the competitiveness or otherwise of the generation sector. The EA's modelling suggests that, relative to the status quo, its proposal gives rise to additional investment in generation capacity of $1,940 million in present value terms, which it proposes not to measure as a cost of its proposal.

It follows that the EA's modelling framework proposes to:

- take into account the benefits associated with this decrease in price, consisting of reduced deadweight losses; but
- not take into account the costs that give rise to this decrease in price, consisting of additional investment in generation.

The inconsistency between these assumptions is self-evident. It cannot be reasonable to capture the benefits associated with the influx of generators that the EA models without also taking into account the costs. The correct approach is that all benefits and all costs associated with the EA's proposal should be taken into account in the analysis.

It is not correct for the EA to assume away distribution costs by stating that its cost benefit analysis 'focuses' on transmission. This is no more reasonable than a view that its analysis should focus only on benefits, rather than costs. Distribution costs follow as a direct result of the increased demand that the EA models as following from its reform and giving rise to benefits in the form of reduced deadweight loss. These increased costs should be incorporated into the analysis.

The EA assumes that increases in peak demand brings forward transmission investment. However, the EA's central estimate of $188 million is inappropriately calculated as the average of two alternative estimates of increased transmission investment under two scenarios, being:

- $324 million under the EA's 'all major capex' scenario; and
- $51 million under the 'demand major capex' scenario.

The 'all major capex' scenario provides central estimates for the key benefits that the EA claims for its grid use model. To be consistent with this, the EA should also adopt central estimates for costs from the same model.

With simple corrections, the EA's grid use model can be shown to estimate net costs of $2,303 million, rather than the net benefits of $2,593 million that it claims. The composition of these estimates is set out at in the table below.

Revised estimates of net benefit from the grid use model

Description	EA's estimate of benefit	Our estimate of benefit
Change in consumer surplus	$2,579 million	$51 million
More efficient investment in batteries	$202 million	$202 million
Increase in transmission costs	-$188 million	-$324 million
Increase in generation costs	n/a	-$1,940 million
Increase in distribution costs	n/a	-$292 million
Total grid use net benefit	**$2,593 million**	**-$2,303 million**

Source: Electricity Authority, HoustonKemp

The cost benefit analysis contains further errors of assumption and approach

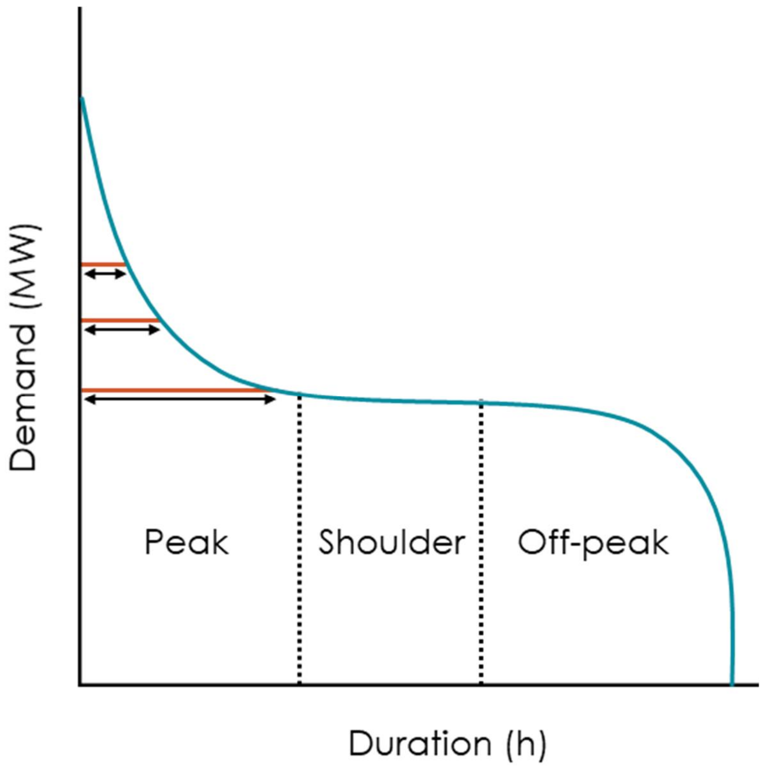
In addition to the errors in the conceptual framework that we identify above, the EA's cost benefit analysis also incorporates material errors of assumption and approach in the implementation of that framework. In our view, the number and nature of the errors that affect its analysis mean that no reliance can be placed on the results of the EA's modelling. We describe examples of four such errors below.

Benefits assume uneconomic investment in batteries in the status quo

The EA's modelling assumes that there will be a surge of inefficient investment in batteries under the status quo in which the RCPD charge continues to apply, amounting to additional investment of $202 million in present value terms. This amounts to an assumption that over 3,000 MW of battery capacity would be installed under the status quo for the purpose of avoiding transmission charges.

These results are implausible. Even under idealised assumptions, in which batteries are assumed to discharge when required, the opportunities for battery investment decline with additional installed battery capacity. As battery investment increases, load in a greater number of periods must be reduced to achieve a reduction in the interconnection charge, as shown in the figure below. This means that the marginal benefit associated with each battery declines increasingly steeply with each additional investment.

Investment in batteries shaves peak demand from the load duration profile



Source: HoustonKemp

The EA's approach to modelling battery investment is in error because:

- its modelling framework is incapable of capturing the declining profitability of marginal investment in batteries; and
- the battery capacity chosen by the model does not reflect an optimal economic decision determined by the model but is the result of a poorly justified relationship imposed within the model and driven by an assumed parameter value.

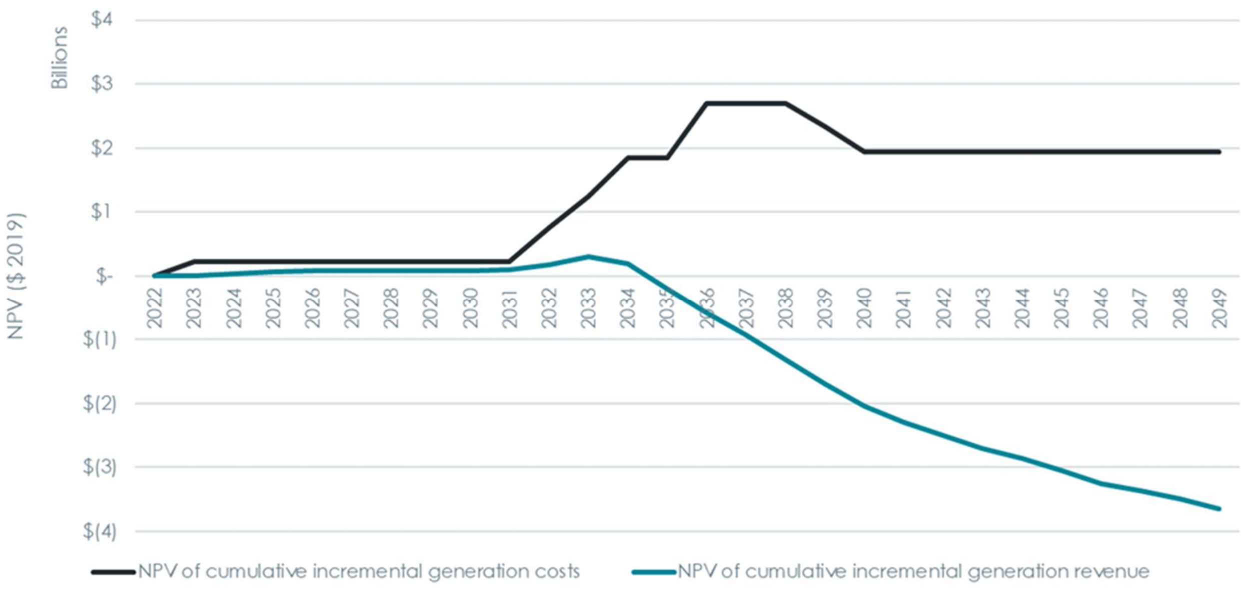
The result of these errors is that the EA's grid use modelling is likely to overstate substantially the extent to which battery investment would be incentivised under the status quo.

Benefits reflect reduced profitability of the generation sector in the wholesale market

Errors in the EA's price formation and generator entry modelling result in significant reductions in the profitability of the generation sector, arising from substantial new investment pushing down wholesale prices leading to reduced generator revenues. Although the EA assumes that progressively more expensive generators are required to enter the market to serve peak demand under its proposal, the result of these errors is that the increased demand predicted by the EA leads to *lower* average wholesale prices, when in fact, more generation investment typically requires *higher* prices.

These errors mean that, on its own modelling, the effect of the EA's proposal is to give rise to an additional $1,940 million of generation investment. However, at the same time total generation revenues reduce by $3,655 million. This means that over the modelling period, generators make $5,595 million less profit under the proposal.

Present value of incremental generation revenues and costs under the proposal



Source: Electricity Authority

Greater scrutiny by stakeholders gives rise to more efficient grid investment

The EA estimates benefits of $77 million associated with greater scrutiny of investment proposals by stakeholders.

Additional scrutiny of investment proposals is said to arise due to the introduction of a benefit-based charge, and to give rise to efficiency benefits of between one and four per cent. The EA's estimate of benefits turns on these assumptions. The empirical rationale for this range of estimates is based on a reduction of 4.4 per cent that the Commerce Commission applied to Transpower's proposed enhancement and development capex in the context of RCP2.

In our view, this is an unreliable basis for estimating the potential benefits associated with additional scrutiny and likely to overstate the benefits, because:

- the EA relies upon the single observation of the Commission's review – this does not provide a reliable basis to conclude that 4.4 per cent reasonably represents the expected outcome of this form of scrutiny;
- it is incorrect to describe changes to Transpower's expenditure program that follow the Commission's review wholly as benefits, since a reduction in expenditure may result in fewer services, lower reliability or increased future expenditure; and
- the basis upon which the EA considers that stakeholders would not just replicate the outcome of the Commission's review processes but improve on them is unexplained.

Consistent with these observations, our view is that any benefits associated with increased scrutiny are likely to be small, relative to the EA's estimate.

More certain policy environment reduces the cost of investment

The EA estimates benefits of $26 million associated with a more uncertain policy environment under its proposal, as compared with under the status quo. The modelling that underpins the EA's calculation of net benefits turns on two unsupported assumptions that determine the magnitude of the benefits that it estimates. These assumptions are that:

- under the EA's proposal, there would be one event of political uncertainty every 11 years, as compared to every 10 under the status quo; and
- the level of uncertainty under the status quo is 100.

The nature of these assumptions discloses that the EA's estimate of the benefits of durability does not rest on any evidentiary basis. It is more accurately described as a contention, rather than an estimate. In our view, the EA should not pursue the calculation of a durability benefit – a benefit that in any case assumes net benefits associated with its proposal that have not been established.

The cost benefit analysis does not reflect best practice

The EA's cost benefit analysis does not follow best practice because:

- it does not explore alternative options to the EA's proposal or test the proposal against potential alternatives, such as excluding the reallocation of seven historical investments on beneficiary-pays principles; and
- it incorrectly specifies the status quo in all scenarios by inappropriately assuming that the RCPD charge would remain at the current strength and give rise to inefficient outcomes, notwithstanding Transpower's ability to change this under the current TPM guidelines.

Alternative options are not explored by the cost benefit analysis

The purpose of cost benefit analysis is to place rigour around the making of a decision to address a problem, so that the decision maker understands the impact that its decision will have both in aggregate and in terms of the distribution of effects. By articulating the costs and benefits of the preferred option, stakeholders form broad expectations as to how the option is likely to perform, which in turn assists in monitoring actual costs and benefits once the option is implemented.

This purpose sits in contrast to the use that the EA makes of cost benefit analysis. The EA appears to be wholly persuaded of the merits of its proposal on the basis of economic principle and the purpose of cost benefit analysis in its consultation paper is limited to verifying the magnitude of the benefits that would be realised by its proposal, rather than seeking to test these in any meaningful way against other options.

By way of example, the EA proposes to reallocate the costs of historical investments, without presenting an alternative option that does not do this. However, on the EA's own estimates, excluding historical investments from the benefit-based charge gives rise to net benefits of $18 million.

The EA's insistence on reallocation of the costs of existing investments has always been perplexing, given its approach to interpreting its statutory objective with a focus on economic efficiency.

Changing the allocation of existing investments provides no prospect of promoting more efficient investment incentives and or achieving more efficient use of the network. Indeed, it is possible that it could instead give rise to increased inefficiency of use, to the extent that the potential for reallocation opens the door for uncertainty about future transmission prices.

The main factor that gives rise to continued contention about the TPM is the foreseeable prospect that the EA might act so as to change the TPM on this basis. This prospect arises not just at the time of the initial allocation, but also with the prospect that there could be further reallocations as evidence emerges about who benefits from an investment. It follows that a far more direct solution to removing contention, reducing uncertainty and improving the durability of the TPM framework is for the EA to commit to limiting the scope of any potential reform to the TPM to be on a prospective basis only – consistent with the approach that is applied in all United States jurisdictions reviewed by the EA.

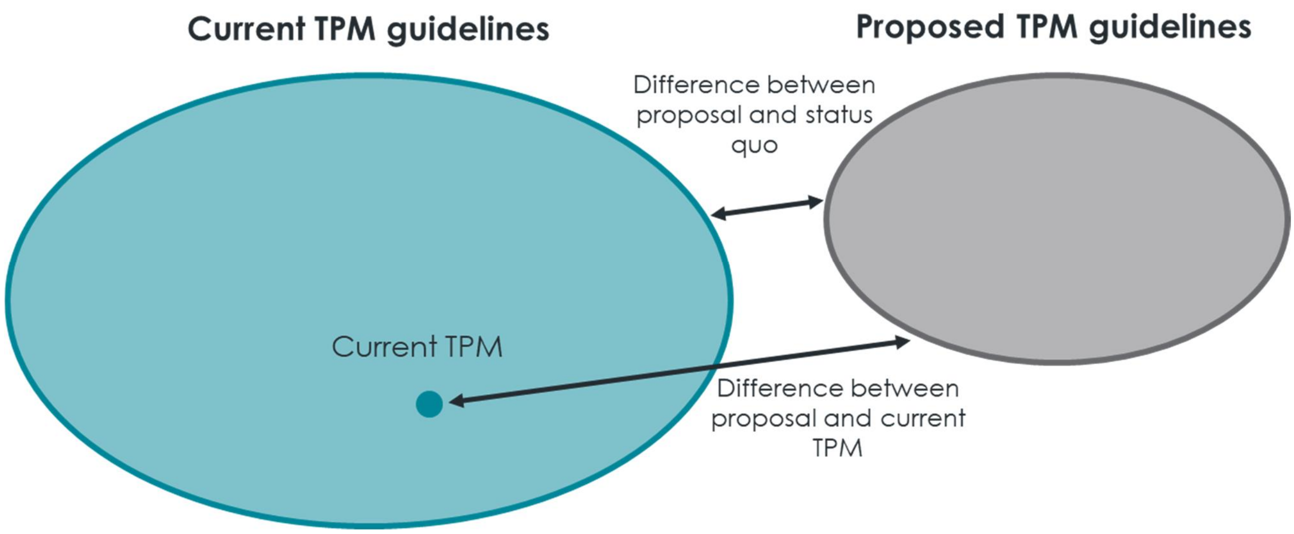
EA assumes that the TPM cannot change under the status quo

Although the EA's cost benefit analysis assesses its proposal against a status quo in which the current TPM continues to apply, the difference between the net benefits arising from its proposal and future TPMs that Transpower could formulate under the current guidelines in response to emerging inefficiencies may be much smaller.

Transpower has flexibility, which it has used in the past, to adjust interconnection charges and the method by which they are recovered to address concerns about the efficiency of price signals. For example, over 2014 and 2015, Transpower conducted an operational review focused on potential inefficiencies with price signals sent by the TPM at that time. The result of the review was changes to the TPM to improve the efficiency of price signals for the interconnection and HVDC charges.

It follows that, in evaluating the costs and benefits of changing the TPM guidelines, the EA should assess the costs and benefits that would result from changing the current flexibility that Transpower has to determine the TPM under its current guidelines. The appropriate factual (or status quo) scenario, is not necessarily a continuation of the current level and basis for charges, but should reflect Transpower's ability to change the TPM to address inefficiencies within the scope of the current guidelines, as we show in the figure below.

Current TPM is formulated within guidelines that the EA proposes to change



The cost benefit analysis assumes the efficacy of the EA's proposal

The benefit-based charge is aimed at addressing the problem that, under a postage-stamp charge, transmission users do not fully internalise the costs their use of the network places on other users. If this use drives new network investment, the costs of this investment are recovered from all users rather than from those who gave rise to the need for the investment

The EA's proposed benefit-based charge will not send a conventional price signal to ration use of the transmission network. Instead, users will be expected to ration their use of the transmission network in response to the prospect of future increases in price – which the EA has previously called a 'shadow price'.

In our view there is little reason to presume that transmission users could accurate or precisely discern a shadow price signal. To believe otherwise assumes that:

- users can discern how their behaviour affects the prospects of a grid upgrade and that consumption below a 'bright line' level will not be affected by the prospect of future charges;
- users can understand how their benefits will be assessed in distributing the costs of an investment and how changes to their actions will affect this distribution; and
- users can anticipate the actions of other users and take these into account in determining their own actions in responding to the shadow price signal.

Even if users were capable of discerning an accurate and precise shadow price, it does not necessarily follow that this would elicit efficient responses.

The EA characterises its proposed benefit-based charge as ensuring that generation and large loads would 'face the full costs' of any required upgrades. However, the benefits of any investment will likely accrue across all users of the investment, and therefore the costs of the investment will be recovered across these users. It follows that under benefit-based charges, no single user (even a user whose actions may give rise to the need for the investment) will internalise the full cost of the investment in its decision making.

The EA further assumes, in computing the costs and benefits of the benefit-based charge, that behavioural change achieved by shadow price signals is sustained. However, any shadow price signal sent in respect of a future transmission investment lasts only until the investment is made. To implement any benefit-based charge, Transpower will need to determine a period over which to estimate benefits. This raises the prospect that behaviour during this period could be temporarily distorted by users with the intent of reducing their allocation of costs for the new investment, rather than as an efficient response to costs. This behaviour would then revert once the investment was made.

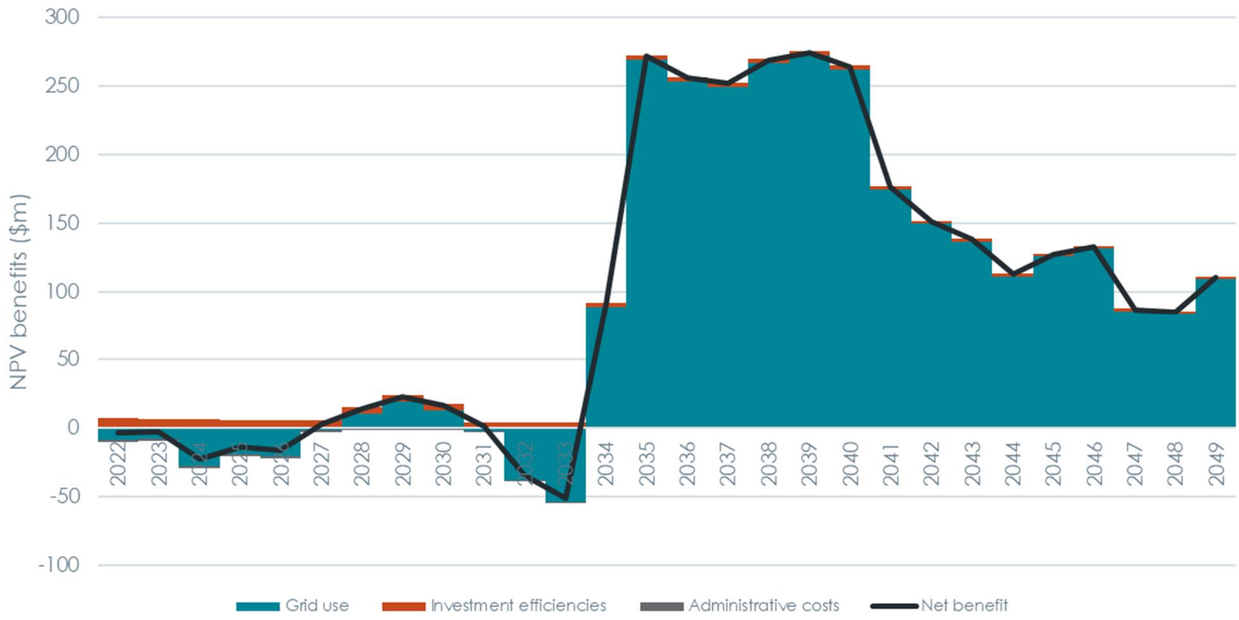
The cost benefit analysis does not support reform in the near term

The EA's cost benefit analysis, without adjusting for any of the deficiencies we have identified, does not support the EA's proposed change to the TPM guidelines in the near term. This is because:

- the EA's cost benefit analysis shows that the benefits of the reform occur towards the end of the modelling period; and
- in any case, many of the benefits predicted by the EA depend on speculative future developments.

The figure below sets out the profile of net benefits estimated by the EA's modelling over time. It shows that the annual net benefits of the reform are projected to be near zero, and fluctuate between small negative and positive values until 2034. There is a huge increase in projected benefits after 2034, to which the entirety of the predicted total net present value of benefits in the EA's cost benefit analysis is attributable.

Net present value of benefits under the EA's proposal, 2022 to 2049



Source: Electricity Authority

The greatest net benefits are achieved if the proposal is implemented so as to come into effect in 2034. This timing gives rise to net benefits that exceed immediate implementation of the EA's proposal by $87 million in present value terms.

Caution regarding the uncertainty of future developments, and the results of the EA's cost benefit analysis itself, suggest that efficient operation of the industry would be promoted by a slower implementation of the proposal than is being considered by the EA.

1. Introduction

On 30 July 2019, the Electricity Authority (EA) released an issues paper, which sets out its proposal to change the guidelines that Transpower must follow in developing the transmission pricing methodology (TPM).[1] The TPM establishes how Transpower's regulated revenues will be recovered from users of the transmission system.

Although referred to as guidelines, the EA's proposal actually consists of a series highly prescriptive instructions to Transpower set out over 20 pages. This level of prescription extends to a determination of the allocation of costs that Transpower should use for seven existing transmission investments. By contrast, the existing TPM guidelines consist of high level principles set out over three pages.

This issues paper is the third proposal that the EA has put forward to change the TPM guidelines, following:

- an initial issues paper and proposal, released on 10 October 2012;[2] and
- a second issues paper and proposal, released on 17 May 2016.[3]

The EA's most recent proposal contains most of the elements set out in its second issues paper and proposal and would amend the guidelines to require Transpower to make fundamental changes to the TPM, including:

- removal of the existing interconnection charge and high voltage direct current (HVDC) charge, which the EA considers promote inefficient investment and usage decisions;
- introduction of two new charges, consisting of:
  - a 'benefit-based' charge on load and generation, which will be designed to recover the costs of certain past and all future investments from transmission customers in proportion to the positive benefits that they receive from those investments; and
  - a residual charge on load, which will recover all costs not recovered from other charges; and
- change to the current approach by which transmission costs are recovered in favour of a reliance on fixed charges which cannot be avoided.

Underpinning its proposal, the EA has prepared a cost benefit analysis, which it says 'gives a sense of the order of magnitude of benefits or costs that are involved'.[4] The EA's cost benefit analysis estimates present value net benefits, measured against a status quo in which the existing TPM continues to apply, of:[5]

- $2,711 million (ranging from $201 million to $6,383 million) in connection with its proposal; and
- $1,853 million (ranging from $130 million to $4,705 million) in connection with an alternative option, which the EA describes as replacing existing charges with a 'broad based usage charge'.

By way of comparison, net benefits of $213.3 million were estimated for the substantially similar proposal published by the EA in 2016.[6]

[1] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019.

[2] Electricity Authority, *Transmission pricing methodology: issues and proposal: consultation paper*, 10 October 2012.

[3] Electricity Authority, *Transmission pricing methodology: issues and proposal: second issues paper*, 17 May 2016.

[4] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 20.

[5] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 21.

[6] Oakley Greenwood, *Cost benefit analysis of transmission pricing options*, 11 May 2016, p 62.

A large part of the data and modelling that underpins the EA's cost benefit analysis was not provided with its consultation paper on 23 July 2019, but instead provided later on 28 August 2019.

This report has been jointly prepared by Daniel Young, Alyse Corcoran, Harry Kleyer and Greg Houston.[7] Trustpower has asked us to review the EA's cost benefit analysis in order to assess whether it provides a reasonable estimate of the net benefits that would be expected to arise from its proposal, and assessment of this against alternative options. In preparing this report the authors have read, and complied with, the Code of Conduct for Expert Witnesses as set out in Schedule 4 to the High Court Rules.

The remainder of this report is set out as follows:

- section two provides an overview of the EA's proposed changes to the TPM guidelines;
- section three describes the cost benefit analysis undertaken by the EA and identifies the key assumptions that it makes and steps that it undertakes;
- section four identifies errors in the conceptual framework for analysis that cause the EA to overestimate the benefits and underestimate the costs of its proposal, such that its proposal gives rise to substantial net costs;
- section five highlights errors of assumption and approach that undermine the reliability of the EA's cost benefit analysis and its results;
- section six observes that the cost benefit analysis does not comply with best practice because it does not conduct an options analysis and does not correctly capture the status quo;
- section seven explains that the cost benefit analysis assumes the efficacy of the EA's proposal, and unpacks why the proposal is not likely to give rise to efficient outcomes; and
- section eight draws on the results of the EA's cost benefit analysis to show that, on its own merits, there is no case for reform of the TPM until 2034.

[7] Daniel, Alyse, Harry and Greg are, respectively, Senior Economist, Economist, Analyst and Director at HoustonKemp. Details of our experience and qualifications are available on our website, www.houstonkemp.com.

2. Overview of the EA's proposal

The EA identifies substantial problems with the current TPM on the basis that it fails to achieve economic efficiency of the electricity market. The core elements of the EA's proposed changes to the TPM consist of the removal of the existing interconnection charge and HVDC charge, and the introduction of a 'benefits-based' charge and a residual charge on load. The EA considers that these changes to the TPM will promote more efficient use of, and investment in, the electricity market.

2.1 Current TPM

The purpose of the TPM is to allocate Transpower's regulated revenue between users of the transmission network. The TPM does not determine the quantum of Transpower's revenue – this role is performed by the Commerce Commission under Part 4 of the Commerce Act.

Under the current TPM, Transpower recovers its regulated transmission revenues through four principal means:

- the loss and constraint excess (LCE), which is generated in the nodal market due to differences between the amounts paid by purchasers and the payments received by generators;
- the connection charge, which recovers the costs of assets that are used to connect customers to the interconnected transmission network;
- the HVDC charge, which recovers the cost of the HVDC interconnector between the North and South Islands; and
- the interconnection charge, which recovers all costs that are not recovered by the other charges.

The EA estimates that Transpower's 2020/21 regulated revenue will be $845 million, exclusive of $3 million of prudent discount and notional embedding agreement charges, of which the interconnection charge is expected to recover the largest proportion, amounting to $580 million.[8]

The interconnection charge is recovered by means of a charge applied to regional coincident peak demand (RCPD). For this reason, it is often also referred to as the 'RCPD charge'. The level of the charge is determined for each customer by reference to their offtake from the grid during the 100 half hours at which regional coincident demand it at its highest, during the capacity measurement period for that region.[9]

The HVDC charge is recovered based on:[10]

- historic anytime maximum injection (HAMI), being the average of the 12 highest injections at a South Island generation connection location during any of the four immediately preceding pricing years; and
- South Island mean injection (SIMI), average total energy injected over a capacity measurement period.

Transpower is currently transitioning HVDC charges to be on the basis of SIMI, such that SIMI will ultimately be measured on the basis of average injection over five years.

[8] Electricity Authority spreadsheet, *'2019 Proposal impacts modelling.xlsx'*, worksheet 'Forecast TPM Revenue'.

[9] Transpower's website, https://www.transpower.co.nz/industry/revenue-and-pricing/pricing, accessed 1 September 2019.

[10] Transpower's website, https://www.transpower.co.nz/industry/revenue-and-pricing/pricing, accessed 1 September 2019.

2.2 Problems with the current TPM

The EA considers that there are substantial problems with transmission pricing under the current TPM. In summary, it describes three areas of concern, being that:[11]

- the recovery of interconnection costs through a strong RCPD peak signals sends inefficient signals for use of the transmission network; and
- the recovery of the cost of the HVDC link through a charge on South Island generators sends inefficient signals for investment in new generation capacity; and
- the current TPM provides poor incentives to scrutinise transmission investment proposals since it spreads the costs of new investments across all customers.

These problems are identified in principle, rather than established in fact. Although the EA highlights several case studies which illustrate how these problems may manifest under stylised assumptions, it does not identify significant examples of inefficient use of the transmission network, inefficient investment in generation capacity or inefficient investment in transmission network capacity.

The EA also considers that the current TPM is not durable because the postage stamp approach means that customers pay for transmission upgrades that they did not benefit from, which has the potential to give rise to continued costly disputes about the TPM:[12]

> There has been long-term and consistent pressure for the TPM to be reformed – it has been under almost constant scrutiny for the last decade at least. This situation creates significant costs in reviewing regulations and lobbying for and against change. The lack of durability also creates uncertainty, which is not conducive for making long-lived investment decisions.

Collectively, these concerns arise from the EA's interpretation of its statutory objective as set out in section 15 of the Electricity Industry Act, that is – 'to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers'.

The EA interprets this objective as requiring it to 'promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers. It states that this requires it to facilitate the achievement of economic efficiency, including:[13]

- dynamic efficiency through providing incentives for the most efficient investments to occur at the most efficient time and the most efficient place; and
- static efficiency through providing incentives for the day-to-day operation of the industry to involve an efficient trade-off between reliability and cost.

This focus on economic efficiency appears to drive all of the EA's concerns about the current TPM, including its concerns about durability. This focus also shapes the EA's response to these concerns, which we describe in section 2.3 below.

2.3 Proposed changes to the TPM

Alongside the review of the current TPM that we summarise above, the EA has developed in parallel new TPM guidelines to address the outcomes of that review.

The EA proposes the amend the TPM guidelines so as to require Transpower to:

[11] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, pp 8-12.

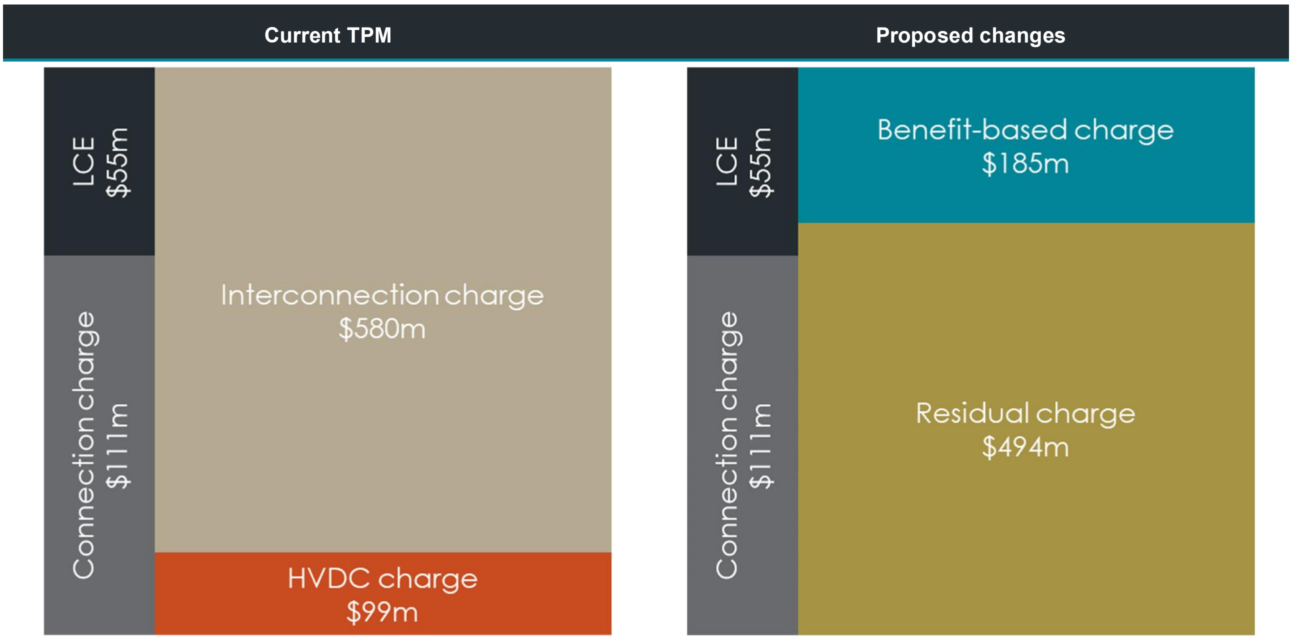
[12] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 2.24.

[13] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para D.2.

- allocate the cost of future transmission investments, and seven historic transmission investment, to users in proportion to their positive benefits from the investment over its remaining life – the EA describes this as a 'benefit-based charge';[14] and
- allocate the residual interconnection costs to users in proportion to their historic anytime maximum demand (AMD), assessed initially over the two years ending 1 August 2019 – the EA describes this as a 'residual charge'.[15]

Figure 2.1 below shows the EA's estimates of how the recovery of Transpower's regulated revenue in 2020/21 would be affected by its proposal. Expected revenue from LCE and connection charges would not be affected by the EA's proposal.

Figure 2.1: Changes to recovery of Transpower's regulated revenue under EA's proposal, 2020/21



Source: Electricity Authority

Below we set out more detail about key aspects of the EA's proposal including:

- the process by which benefit-based charges are to be calculated and amended;
- the process by which residual charges are to be calculated and amended;
- the limits on which transmission charges can change under a cap proposed by the EA; and
- the additional components within the proposal that Transpower must consider.

2.3.1 Benefit-based charges

Benefit-based charges would be used to recover the costs of benefit-based investments, which are:[16]

[14] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, paras 22-23.

[15] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, para 40.

[16] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, paras 42-43.

- any transmission (or transmission alternative) investment that is commissioned after the publication of the EA's consultation paper and which at the time of commissioning constitutes Transpower's base capex or major capex; and
- seven existing major transmission investments, namely: the Bunnnythorpe-Haywards reconductoring project; investments in and associated with the HVDC link; the lower South Island renewables project; the lower South Island reliability project; the North Island grid upgrade project; the upper North Island dynamic reactive support project; and the Wairakei ring project.

Transpower would be required to develop a charge for *each* of these investments. To achieve this, it must develop a 'standard' method and a 'simple' method for allocating the cost of benefit-based investments. The standard method would be applied to investments that exceed the Commerce Commission's 'base capex threshold' (currently $20 million), whereas the simple method would apply to other investments. However, for the seven existing major investments, Transpower would be required to use the allocation calculated by the EA in its consultation paper.[17]

Once allocated, the share of annual benefit-based charges cannot change – that is, the charge is fixed. However, the proposed TPM guidelines also specify that Transpower can review the allocation of benefit-based charges in circumstances in which:[18]

- there is (or will be) a 'substantial and sustained' change in grid use affecting benefits derived by transmission users from a benefit-based investment; and
- this change in circumstances was not factored into the calculations used to allocate the relevant charges.

In circumstances in which the benefits associated with an investment decline to less than 80 per cent of its current value, transmission users may apply to Transpower to revise the benefit-based charge to reflect the investments' changed value and to reassign the remaining costs to be recovered by the residual charge.[19]

2.3.2 Residual charge

The residual charge would be used to recover any part Transpower's revenue allowance which is not recovered through other means.[20]

The residual charge is to be allocated to transmission users in proportion to historical AMD. It follows that, as with benefit-based charges, the residual charge for each customer cannot be altered by changes in that users' behaviour.[21] Once the basis for recovering residual charges from an individual user has been determined, this can only change under circumstances that involve:[22]

- the entry of new large loads or generators, or new investments by existing large loads or generation that give rise to a 'substantial and sustained' increase in use or injection;
- the sale of part of the business of a transmission customer, in which case its benefit-based charges will be spread across the original and new owners;

[17] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, Appendix A: Proposed TPM guidelines, 23 July 2019, paras 13 and 21.

[18] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, Appendix A: Proposed TPM guidelines, 23 July 2019, para 26.

[19] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, Appendix A: Proposed TPM guidelines, 23 July 2019, paras 34 and 38.

[20] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, Appendix A: Proposed TPM guidelines, 23 July 2019, para 39.

[21] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, Appendix A: Proposed TPM guidelines, 23 July 2019, para 40.

[22] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, paras 42-43.

- the use of a prudent discount policy to avoid creating inefficient incentives for a large load or generator to shift its point of connection; or
- the over-recovery by Transpower of its forecast revenue allowance, in which case charges may be scaled back to prevent this outcome.

2.3.3 Cap on transmission charges

Transpower must provide for a cap that applies to the total of each load customer's transmission charges from benefit-based charges for new (but not existing) transmission investments and residual charges.[23]

The total transmission charges for each distributor are capped such that they can only increase by a proportion of Transpower's estimate of the total electricity bill for customers supplied by that distributor in the 2019/20 year, where that proportion is determined as:[24]

- 3.5 per cent; plus
- the change in the consumer price index since the 2019/20 pricing year; plus
- the increase in the distributor's load since the 2019/20 pricing year.

The total transmission charges for each direct load customer are capped such that they can only increase by a proportion Transpower's estimate of the customer's total electricity bill in the 2019/20 pricing year, where that proportion is determined as:[25]

- 3.5 per cent; plus
- the change in consumer price index since the 2019/20 pricing year; plus
- the increase in the direct customer's load since the 2019/20 year; plus
- two per cent multiplied by the greater of zero and the number of years that have elapsed since the 2024/25 pricing year.

Where the price cap results in a reduction in transmission charges for a load customer, the forgone revenue is recovered by a surcharge on the benefit-based charge for existing major investments and the residual charge across all customers.[26]

If the price cap does not have the effect of reducing transmission charges for a load customer in any year, then the price cap ceases to apply in all subsequent years.[27]

2.3.4 Additional components

In addition to the core elements of its proposal, the EA's proposed TPM guidelines also contain seven additional components.

[23] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, para 49.

[24] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, para 50(i).

[25] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, para 50(j).

[26] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, para 51.

[27] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper | Appendix A: Proposed TPM guidelines*, 23 July 2019, para 50(k).

The proposed guidelines specify that:[28]

> The **TPM** must incorporate each of the following **additional components**, where including that component would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**. [Emphasis in original]

Our understanding of these requirements is that Transpower must:

- consider the additional components; and
- evaluate the inclusion of each additional component against a counterfactual of not including that component.

Table 2.1 below describes the additional components that Transpower is required to consider under the proposed TPM guidelines.[29]

Table 2.1: Additional components under the EA's proposal

Additional component	Description
A. Staged commissioning	Transpower provides a method to deduct connection charges that are already recovered from the calculation of the benefit-based charge for an investment that is commissioned in stages so that it is first a connection asset and then an interconnection asset.
B. Charges for assets principally providing connection services	Transpower provides a method to ensure that interconnection assets that substantively provide connection services are treated like connection assets even if they do not technically meet this definition.
C. Charges for connection assets	Transpower provides a method to align the calculation of annual charges for new connection assets with the method used to calculate annual benefit-based charges for new interconnection investments.
D. Transitional peak charge	Transpower provides a method for determining the level of a transitional peak charge, the customers or areas to which it would apply and its allocation across those customers, with the requirement that: • a transitional charge may only apply in circumstances in which congestion would otherwise be experienced and Transpower must explain why demand will not be controlled by other means, such as nodal prices; • a transitional peak charge must be phased out, with the phase-out to begin within one year after it is imposed and ending no later than five years after it is imposed. Transpower must set out the path of this transition; and • Transpower must obtain the Authority's approval to pause or delay transition, or to reinstate or introduce a new transitional charge.
E. Including additional pre-2019 investments in the benefit-based charge	Transpower provides a method for determining whether benefit-based charges should be applied to other historical investments other than the seven already proposed by the EA.
F. Charging for opex	Transpower provides a method for connection and benefit-based charges to include an allocation of operating costs.
G. Kvar charge	Transpower provides a method for imposing a kvar charge on reactive power.

Source: Electricity Authority

The EA's cost benefit analysis, which we describe in section 3 below, does not assess the additional components, either on their own merits or against other options, even though it is mandatory for Transpower to consider them. Once the TPM guidelines are adopted, Transpower will itself undertake a cost benefit analysis for the additional components, but only to assess whether to include them or not, rather than an assessment against alternative options.

[28] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, Appendix A: Proposed TPM guidelines, 23 July 2019, para 54.

[29] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, Appendix A: Proposed TPM guidelines, 23 July 2019, paras 55-65; and Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 15.

2.4 Advantages cited for the proposal

The EA cites four advantages that it considers would be promoted by its proposal.[30]

First, it states that the introduction of a benefit-based charge will ensure that customers who benefit from an investment would be charged for it, which would, amongst other things:

- reduce incentives to make inefficient investments to avoid being allocated transmission costs;
- ensure that generation and large load making location and other investment decisions take transmission costs into account; and
- promote increased scrutiny of investment proposals and encourage customers to reveal truthful information about the benefits and costs of these proposals.

Second, it considers that the use of fixed charges will ensure that revenue recovery does not distort grid use or investment decisions, ensuring that customers cannot avoid charges by changing their behaviour.

Third, it considers that the removal of the RCPD charge would better allow the nodal market to provide a greater role in signalling grid congestion.

Finally, it claims that benefit-based charges are more likely to be regarded as 'fair and reasonable' because the concept underpinning it would not be contentious. It follows that the EA's proposal would be more 'durable' than the current approach to transmission pricing, which would allow efficiency benefits to be achieved and would reduce the costs of making investments by bringing greater certainty to TPM arrangements.

[30] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, paras 3.25-3.26.

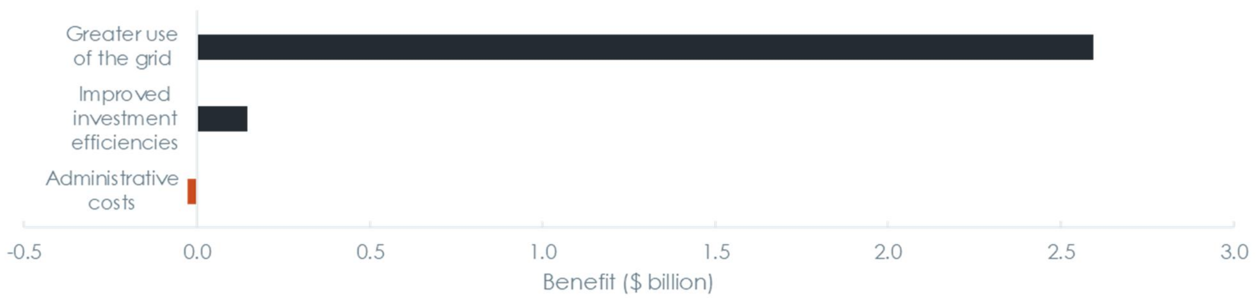
3. EA's cost benefit analysis

The EA's quantifies the net benefits of its proposal using a cost-benefit analysis. The net benefits of the changes can be conceptualised as deriving from three distinct sources, ie:

1. **Greater use of the grid**, which measures the potential benefits associated with removing (or reducing the strength of) the RCPD charge.
2. **Improved investment efficiencies**, which measures the potential benefits associated with introducing benefit-based allocation of the costs of future transmission investments.
3. Offsetting items 1 and 2, are the **administrative costs** of developing, implementing and operating a new TPM under the EA's proposed TPM guidelines.

We illustrate the magnitude of these benefits and costs in figure 3.1 below, and describe the EA's analysis of each of these categories of benefits and costs in the remainder of the section.

Figure 3.1: Categories of benefits and costs estimated in the EA's analysis



Note: figure excludes $1 million of costs associated with the price cap
Source: Electricity Authority

3.1 Greater use of the grid

The benefits estimated by the EA as arising from greater use of the grid account for around 96 per cent of the total pool of benefits identified.

The EA considers that removal of the RCPD charge will eliminate a signal that causes (or will cause) end-users to inefficiently reduce consumption at peak times leading to greater use of the grid. Associated with these changes, it estimates:

- $2,579 million of benefits through more efficient grid use (ie, greater use of the grid at peak times and reduced wholesale electricity prices at all times of use);
- $202 million of benefits through avoided inefficient investments in batteries to avoid peak transmission charges; and
- $188 million of costs through greater transmission investment.

These benefits and costs are illustrated at figure 3.2 below.

Figure 3.2: Categories of benefits and costs attributable to greater use of the grid

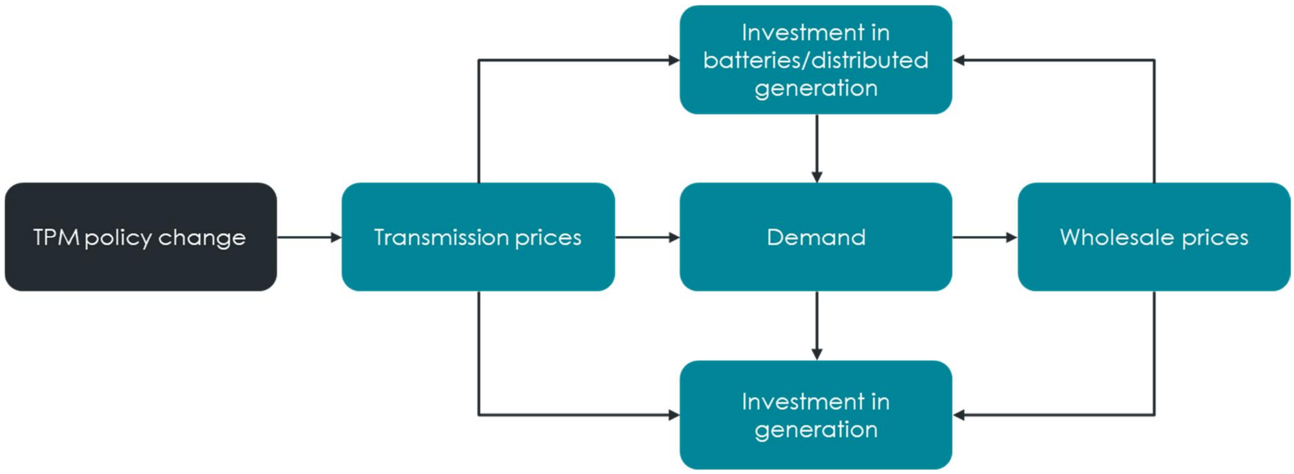
Source: Electricity Authority

The key logical steps that the EA undertakes to explain how the removal of RCPD charges results in greater use of the grid are:

- changes in the structure of interconnection charges are passed from distributors to retailers and further to consumers, giving rise to changes in behaviour;
- demand elasticities estimated by the EA are used to predict changes in consumer behaviour resulting from changes to the structure of interconnection charges;
- under the status quo:
  - interconnection costs are recovered only in peak periods, whereas under the proposal this recovery would instead be spread evenly across time; and
  - high peak prices relative to shoulder and off-peak prices drive a surge in investment in batteries, much of which will be inefficiently incurred to avoid interconnection charges;
- under the proposal:
  - interconnection costs are recovered evenly across time;
  - lower peak prices and reduced battery investment will promote higher demand in peak periods, driving initially higher average prices and entry of new generation;
  - increased entry of generation capacity will lead to a reduction in wholesale prices across shoulder and off-peak periods;
  - lower wholesale prices will give rise to further benefits to consumers; and
  - higher demand in peak periods will drive additional investment in transmission capacity.

Figure 3.3 below demonstrates the logical linkages that are assumed by the EA's modelling.

Figure 3.3: Structure of EA's modelling of grid use benefits and costs



3.1.1 Overview of the grid use model

The EA models the benefits arising from more efficient grid use and more efficient battery investment through its 'bespoke' grid use model.[31] The model takes input data on volumes and prices of generation and demand, and outputs volumes and prices for the subsequent year, given interactions between demand, wholesale prices and generation investments.[32]

The grid use model is comprised of three models:[33]

1. A model of consumer electricity demand, which is used to:
   i. find the effect of changes to transmission charges on electricity demand; and subsequently
   ii. find the effect of change in electricity demand on consumer welfare.
2. A model of investment in grid-connected generation, which is used to find the effect of change in electricity demand on investment in grid connected generation and wholesale energy costs.
3. A model of distributed energy resource (battery) investment, which is used to find the effect of changes to transmission charges on investment in distributed energy resources.

The model distinguishes between four categories of demand by time of use and energy source, ie:[34]

- grid offtake during demand peaks (the top 1,600 half hour trading periods in a year);
- demand served by distributed generation during demand peaks;
- demand met by grid offtake and distributed generation during shoulder periods (the highest 3,075 half hour trading periods in a year, after the peak); and
- demand met by grid offtake and distributed generation during off-peak periods (the lowest 12,845 half hour trading periods in a year).

[31] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 5.

[32] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 24.

[33] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, pp 12 and 27.

[34] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 27.

The EA applies its grid use model to 14 different 'scenarios', reflecting different combinations of input assumptions. However, we understand that 'all major capex' is its central scenario. The EA describes this scenario as:[35]

- testing the effects of implementing the proposal on demand;
- taking into account the potential effects on investments in batteries and on grid generation; and
- incorporating forecast revenue from unapproved major capex.

For clarity of exposition, in describing the EA's grid use modelling, we focus on the results of the central scenario unless otherwise stated. It is not practicable to summarise the results of other scenarios in this report.

3.1.2 Bespoke demand modelling is used to estimate changes in behaviour

The EA develops estimates of demand elasticities to predict the magnitude of changes in consumer behaviour resulting from changes to the structure of interconnection charges. It estimates the short run elasticity of industrial demand and mass market customers separately, giving rise to:[36]

- a price elasticity of demand of -0.02 for industrial demand customers;
- a price elasticity of demand of -0.11 for mass market customers; and
- an income elasticity of demand of 0.11 for mass market customers.

The EA also estimates a long run elasticity of demand for mass market customers of -0.74, which it uses in its investment efficiencies model.[37]

Elasticity for industrial demand

The EA estimates the elasticity of industrial demand by fitting a 'translog cost model' – a system of equations that expresses shares of expenditure on production inputs as a function of the prices of those production inputs – to industry data from 1990 to 2016. These inputs are capital, labour, electricity, non-electricity energy products and other intermediate goods, giving rise to a system of five equations. By way of example, the share of expenditure on electricity is given by:[38]

$$s_e = \beta_e + \delta_{ek}p_k + \delta_{el}p_l + \delta_{ee}p_e + \delta_{en}p_n + \delta_{ei}p_i$$

The coefficients on price (ie, δ_{ij}) arising from this estimation are substituted into an equation to derive the own price elasticity of each production input. By way of example, the electricity own price elasticity (η_{ee}) is given by:[39]

$$\eta_{ee} = \delta_{ee} + s_e(s_e - 1)$$

The relevant coefficient arising from the EA's translog cost function is δ_{ee}, since this feeds into the equation for the electricity own price elasticity, above. The estimate of this coefficient is -0.010, which is associated

[35] Electricity Authority note, *About.txt*, available on its website.

[36] Electricity Authority, *AoB_All_Major_Capex.py*, available on its website.

[37] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, Table 10, p 40.

[38] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, Equation 15, p 34.

[39] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, Equation 18, p 36.

with a p-value of 0.68.[40] The EA applies this coefficient, and an electricity share of expenditure of 0.013 to derive an elasticity estimate of -0.022.

Elasticity for mass market customers

The EA estimates the elasticity of demand for mass market customers using a 'dynamic panel model'. This involves running a regression of electricity demand (x_{rt}) as a function of wholesale prices, inclusive of transmission charges (p_{rt}), while accounting for regional differences, delayed adjustments to price changes (ie, a lagged demand term x_{rt-1}), income (e_{rt}), heating degree days (d_{rt}), and interaction between prices and distributed generation ($d_{rt}p_{rt}$), ie:

$$x_{rt} = a_r + \beta_p p_{rt} + \beta_l x_{rt-1} + \beta_e e_{rt} + \beta_h h_t + \beta_d d_{rt} + \beta_i d_{rt} p_{rt}$$

The EA's regression produces a coefficient estimate for β_p of-0.110, which is associated with a p-value of 0.01. This is their estimate of short run price elasticity of demand for electricity.

The regression produces a coefficient estimate for β_e of 0.11, which is associated with a p-value of 0.30. This is the EA's estimate of short run income elasticity of demand for electricity.

The EA estimates a long run elasticity of demand as -0.74, calculated as:

- its estimate of short run elasticity of demand (-0.11); divided by
- one less its coefficient for lagged demand (0.85).

3.1.3 Changes in the structure of interconnection charges flow through to consumers

The EA's grid use modelling rests on a simplifying assumption that consumers are exposed to transmission price and wholesale price signals. More specifically it assumes that RCPD charges will:

- pass from distributors to retailers through distribution prices that reflect the structure of the RCPD charge; and
- pass from retailers to consumers through retail prices that reflect the structure of the RCPD charge.

To the extent that these assumptions are not correct, the EA assumes that distributors and/or retailers would undertake actions to mitigate their risks that would result in the same outcomes.[41]

3.1.4 Proposed changes spread recovery of interconnection costs across time

Under the EA's proposal, the changes to the spread of interconnection costs across times of use result in an increase in allocative efficiency, ie, a reduction in deadweight loss associated with raising interconnection revenue.

The EA models transmission charges:[42]

- under the status quo, as a per MWh charge during peak periods; and
- under the proposal, the interconnection charge is a per MWh charge during all time of use periods.

[40] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, Table 8, p 36. The p-value indicates the probability that, under the assumption that the coefficient is equal to zero (ie, there is no relationship between the dependent and independent variable), sampling variation would produce an estimate that is further away from zero than the estimate obtained from the regression. The smaller the p-value, the stronger the evidence that the coefficient is not equal to zero. A coefficient that is significant at a given 'level of significance' has a p-value smaller than that level of significance.

[41] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.44, p 28.

[42] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.41, p 28.

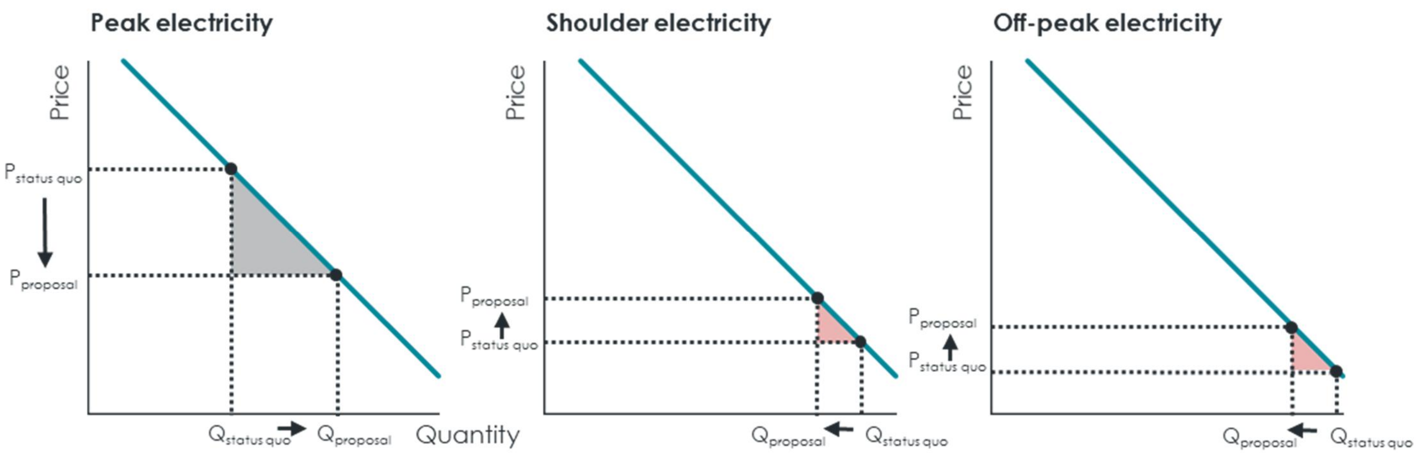
More specifically, under the status quo, the EA models the RCPD charge to be levied against average MWh consumption during the peak period, ie, the top 1,600 trading periods.[43] Under the proposal, the RCPD charge – a fixed charge – is modelled as a per MWh charge.[44]

The EA assumes that consumer time of use demand decisions take into account relative (not absolute) prices and reasons that applying the same MWh charge to all times of use has no net effect on consumers' electricity demand decisions.[45]

The net benefit of the proposed change under this modelling framework, illustrated at figure 3.4 below, reflects:

- the reduction in deadweight loss at peak times, caused by the reduction in interconnection charge recovered in these periods being reflected in higher consumption at lower prices; as against
- the increase in deadweight loss at shoulder and off-peak times, caused by the increase in interconnection charge recovered in these periods being reflected in lower consumption at higher prices.

Figure 3.4: Initial effect on prices and quantities of removing the RCPD charge



The EA states, '[t]he most important aspect of the proposal from the perspective of the efficiency of grid use is the removal of the RCPD charge.'[46] The RCPD charge would be replaced by a residual charge to recover any costs remaining (after the recovery of other transmission charges) in a manner which does not distort incentives to invest or use the grid.[47] In other words, the charge to replace the RCPD charge under the proposal would raise effective energy prices at all times. The EA states this would result in minimal distortion of grid use.[48]

However, the effects of the removal of the RCPD charge modelled by the EA are not limited to this change in allocative efficiency. We describe additional changes that flow from the removal of the peak RCPD charge below.

[43] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 2.9, p 13.

[44] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 2.10-2.11, p 13.

[45] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 2.11, p 13.

[46] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.36, p 26.

[47] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p iii.

[48] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.30, p 26.

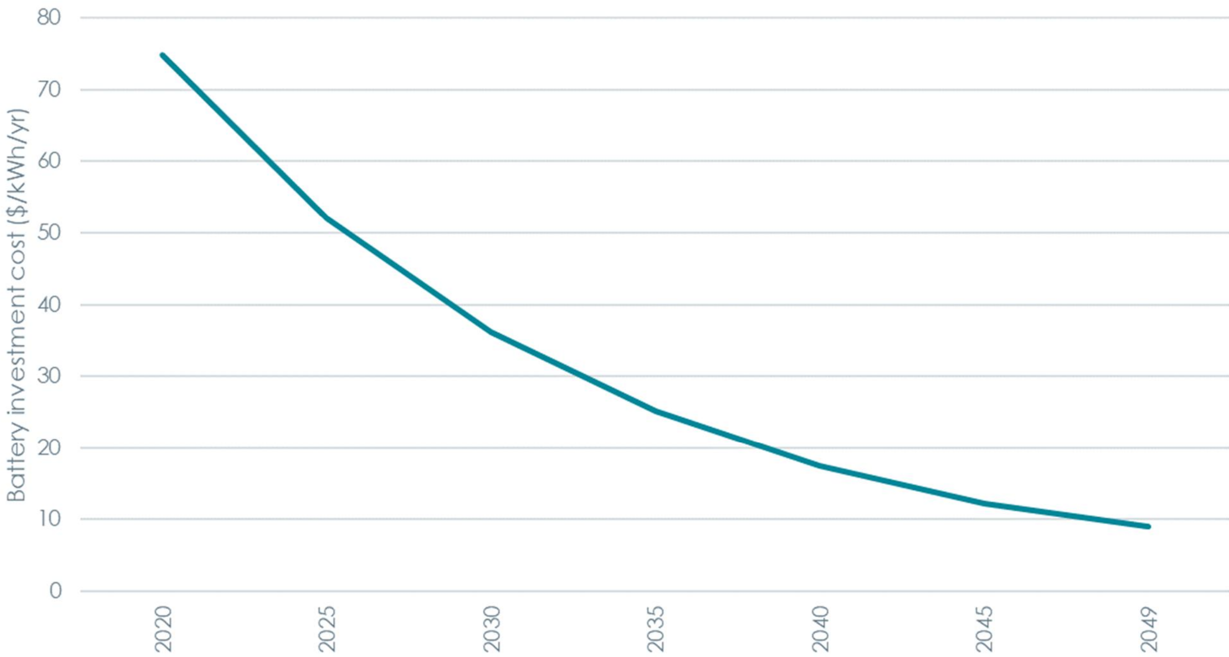
3.1.5 There will be a surge in inefficient investment in batteries under the status quo

The EA claims the proposal will generate $202 million in benefits as a result of avoided inefficient investments in batteries.[49] This claim is based on two principal observations:

- under the status quo, the RCPD charge will continue to send a strong peak price signal, relative to shoulder and off-peak periods; and
- as batteries costs decline, the strong peak price signal will drive a large increase in battery investment, relative to what would otherwise occur under the EA's proposal.

Figure 3.5 shows that the EA assumes that battery costs will reduce by approximately seven-fold over the period from 2020 to 2049.

Figure 3.5: EA assumes that battery costs decline, 2020 to 2049



Source: Electricity Authority

The EA states that battery investment that does not reduce networks costs is inefficient:[50]

> The investment is inefficient if this doesn't change transmission costs to be recovered. (That is, if customers invest in batteries that are cheaper than peak electricity prices including peak transmission charges, but which are more expensive than peak electricity prices excluding uneconomically high transmission charges.)

In the grid use model, batteries enable the shifting of demand between peak and shoulder or off-peak periods. Battery investment under the status quo and proposal is modelled using the EA's grid use model where:[51]

[49] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, table 4, p 21.

[50] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.102, p 38.

[51] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, pp 55-60.

- under the status quo consumers will invest in batteries to avoid peak transmission charges, as well as arbitrage between peak and shoulder prices; and
- under the proposal consumers will only invest in batteries to arbitrage between peak and shoulder prices.

These assumptions mean that battery revenue increases with the expected peak transmission charge and with the difference in prices that apply in peak periods as against those that apply in shoulder and off-peak periods.[52]

If net revenue exceeds capital costs in a given year, the EA assumes that consumers add an amount of batteries to their stock that is proportional to:[53]

- the ratio of net revenue to costs;
- an assumed investment elasticity, the level of which is not stated by the EA; and
- a function increasing in demand and decreasing in existing battery stock.

Acknowledging that the profitability of additional battery investment declines with greater capacity of existing batteries, the EA caps the amount of total battery investment possible in the model.[54]

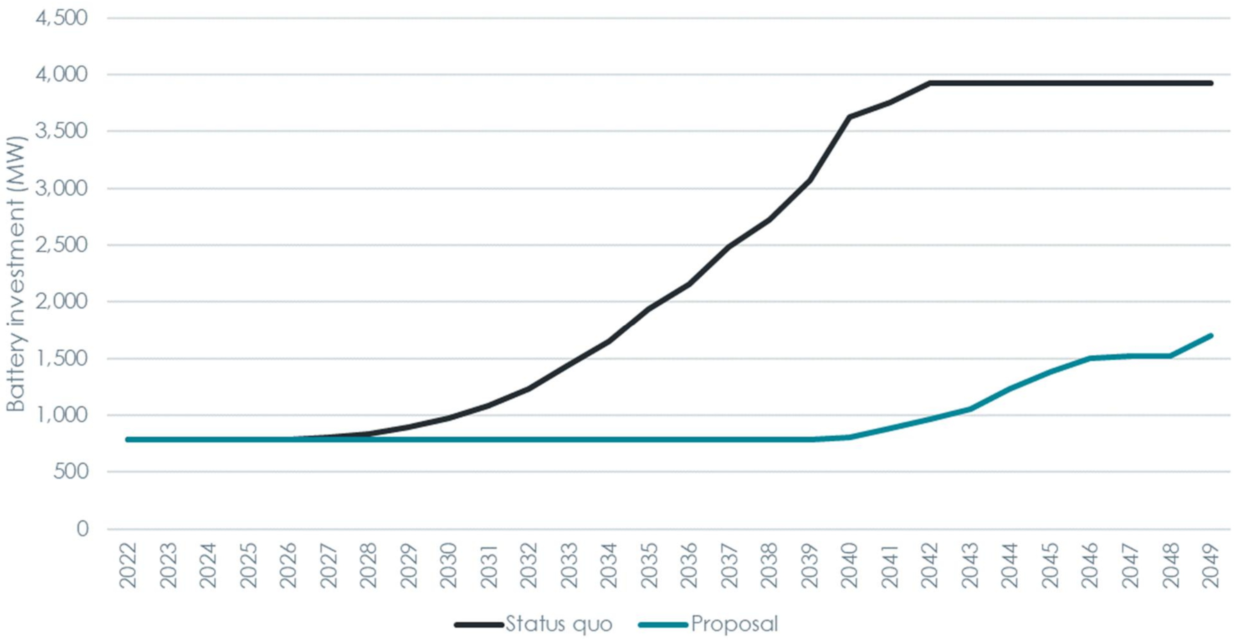
Figure 3.6 shows the path of battery investment modelled under the status quo and the proposal using the assumptions above. The figure shows that over 3,000 MW of battery capacity is assumed to respond to the peak price signal sent by the RCPD charge, represented by the additional battery investment under the status quo relative to the proposal from 2040.

[52] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 27, p 60.

[53] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 29, p 60.

[54] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 2.245, p 60.

Figure 3.6: EA's estimated path of battery investment, 2022 to 2049



Source: Electricity Authority

The EA estimates the value of inefficient battery investment under the status quo as:

- the present value of battery investment under the status quo; less
- the present value of battery investment under the proposal.

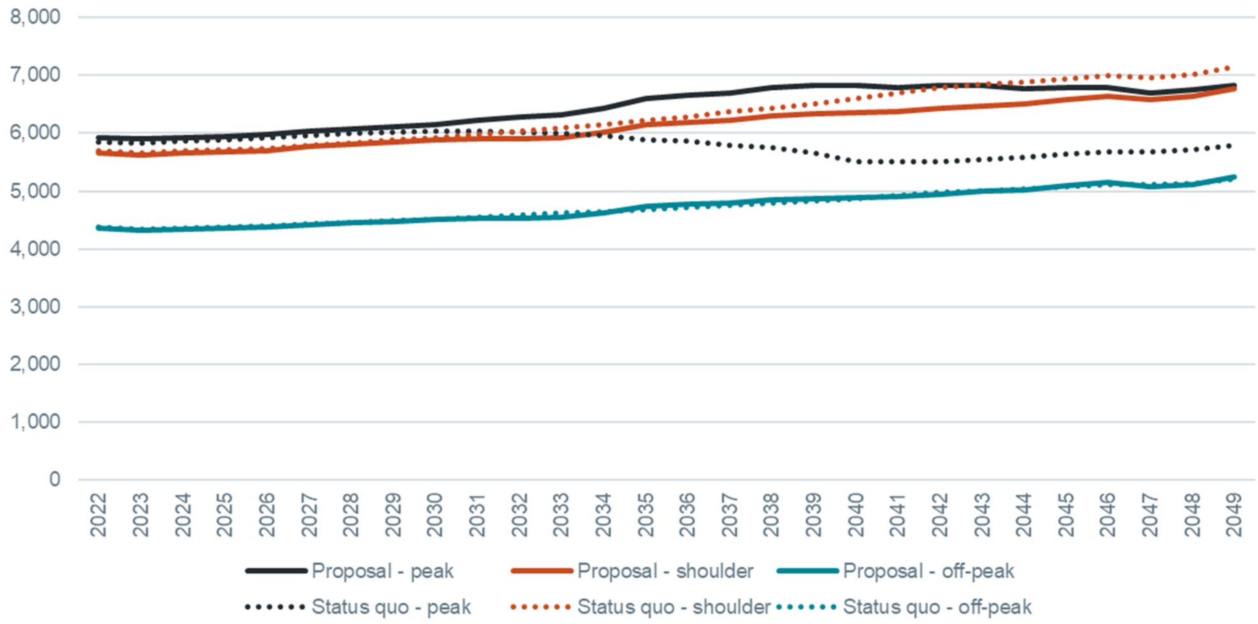
In other words, the EA assumes that battery investment that responds to the price signals modelled under the proposal is efficient.

3.1.6 Higher peak demand and higher peak prices drive additional investment in generation under the proposal

The EA estimates that peak demand in the wholesale market will be significantly higher under its proposal than under the status quo.

This is demonstrated in figure 3.7 below, which shows the EA's estimates of demand in the peak, shoulder and off-peak periods between 2022 and 2049.

Figure 3.7: EA's estimates of demand in the peak, shoulder and off-peak periods, 2022 to 2048



Source: Electricity Authority

The higher level of peak demand under the proposal, relative to the status quo, is driven by:

- lower prices (inclusive of transmission charges) in peak periods due to the removal of the RCPD charge; and
- reduced battery investment due to lower incentives to avoid peak transmission charges.

Higher demand gives rise to higher prices

Within the EA's grid use model, peak, shoulder and off-peak prices are based on the short run marginal cost of available generation capacity in each period.[55]

Prices for each year are estimated by ordering the supply offered by each generator existing in that year by short run marginal cost (SRMC), from smallest to largest, and setting the price equal to the SRMC of the last generator needed to meet demand.[56]

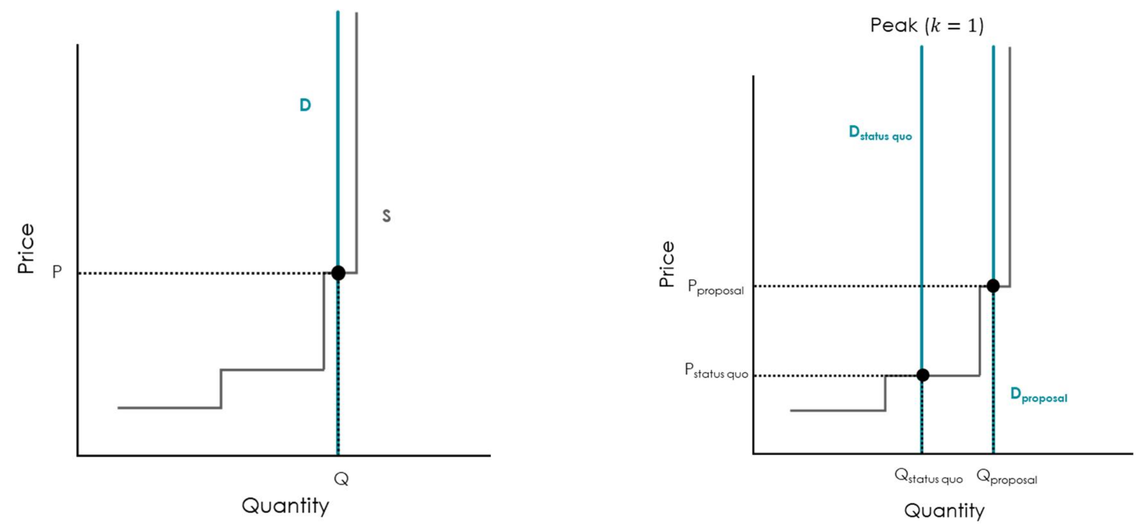
Figure 3.8 below illustrates how price is estimated by reference to the intersection of the SRMC curve (**S**) and demand (**D**) during a peak period. Under this pricing framework, higher peak demand under the proposal drives higher peak wholesale prices by requiring a generator with a higher SRMC to be used to meet demand. Figure 3.8 illustrates this by showing how an increase in peak demand causes the demand curve to intersect the SRMC supply curve at the offer of a higher SRMC generator.

[55] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 2.191, p 47.

[56] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 2.191, p 47.

Figure 3.8: Calculation of price using short run marginal cost curves

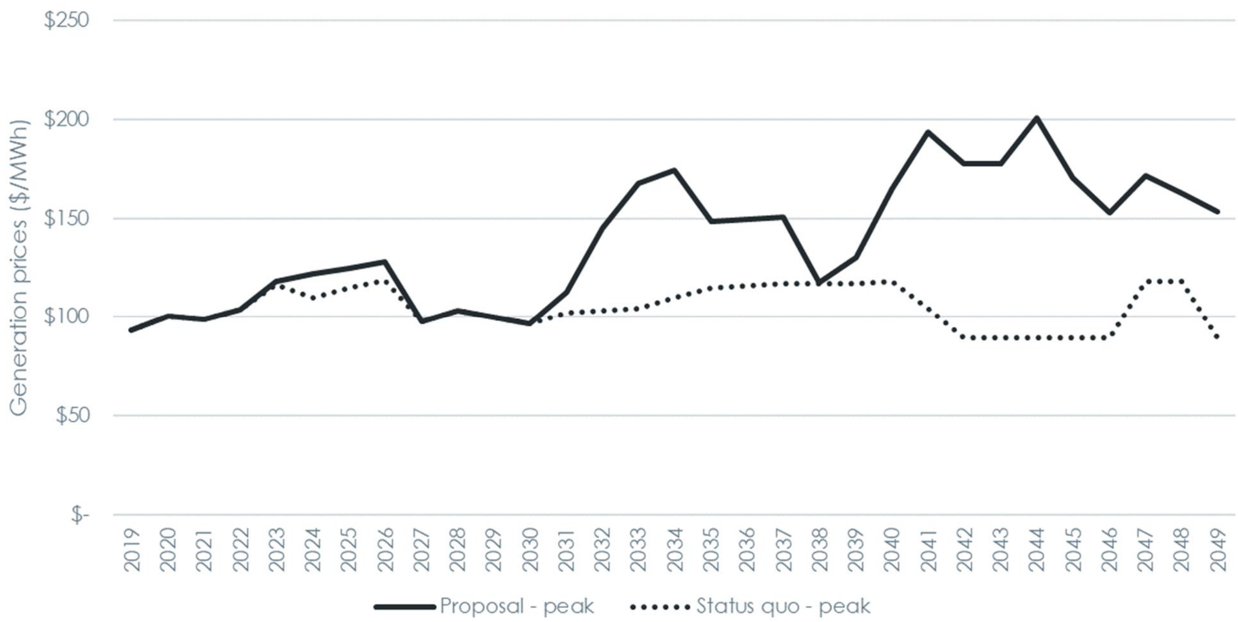
Price is determined at the intersection of demand and supply	Increases in peak demand lead to higher peak prices



Source: HoustonKemp

The effect of this increased peak demand under the proposal on peak wholesale prices can be seen in Figure 3.9 – showing sustained higher peak prices from 2030 onward.

Figure 3.9: Weighted average peak wholesale prices, 2019 to 2049



Source: Electricity Authority

Higher prices give rise to more investment in generation

The EA uses a model of investment in grid connected generation, a component of its grid use model, to estimate the response of investment in generation to higher prices.

The EA's generation investment model considers a schedule of potential investments and assumes entry will occur in a given year if:[57]

- the investment is considered 'profitable'; and
- the number of investments in the given year does not exceed a specified cap of two.

A generation investment is considered 'profitable' whenever the revenue a generator would receive, were it to dispatch its entire offered capacity in each period of the year, is greater than the sum of the long run marginal cost (LRMC) of the investment in that year and the interconnection charges at that node.[58]

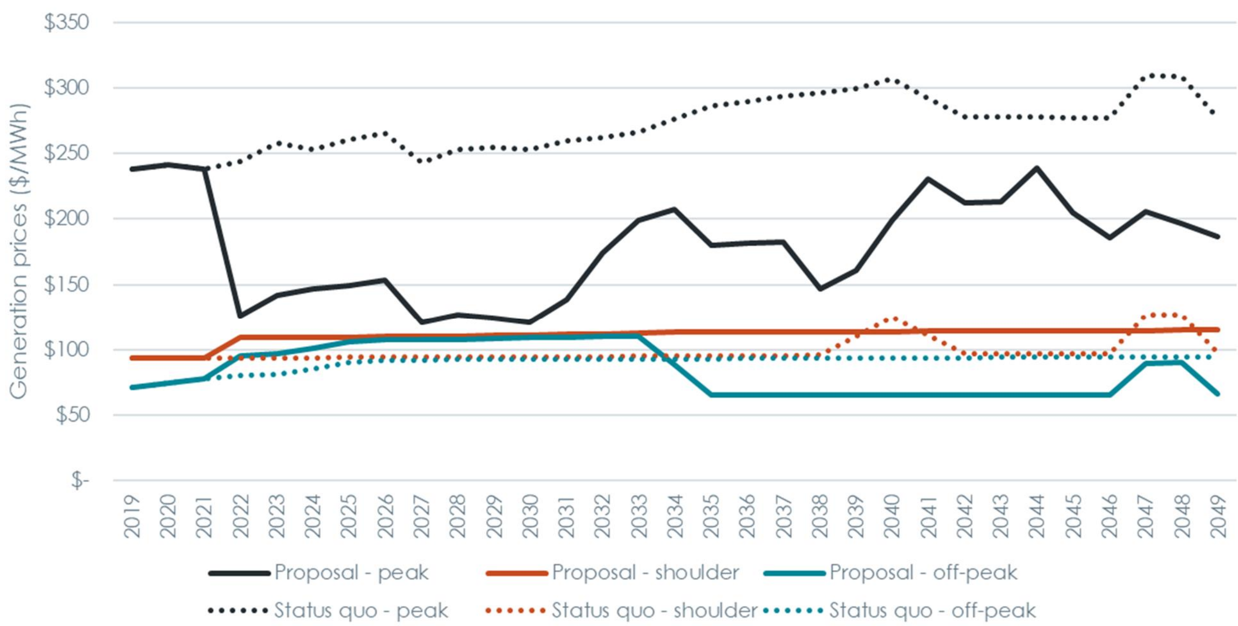
A cap on generation investment is required because generation entry is assumed to affect prices only in subsequent years.

3.1.7 Increased generation capacity gives rise to lower average prices in the wholesale market

The EA's modelling predicts that average final prices (including transmission charges) across all times of use will be lower under the proposal, relative to the status quo, with the most substantial reductions occurring in peak charges.

Figure 3.10 shows the profile of weighted average final prices across peak, shoulder and off-peak periods under the EA's modelling of the 'all major capex' scenario.

Figure 3.10: Weighted average final peak, shoulder and off-peak prices, 2019 to 2049



Source: Electricity Authority

[57] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 25, p 54.

[58] Electricity Authority code, *All_major_capex.py*, lines 436-487. The generation investment decision is contained in the *invest_gen* function.

The EA derives this result from the combined effects of wholesale prices and transmission charges, with the higher peak wholesale price under the proposal offset by the relatively greater reduction in peak transmission charges

Lower final shoulder and off-peak prices under the proposal, on the other hand, are driven by decreased wholesale prices in the shoulder and off-peak periods attributable to increased low cost generation capacity.

Figure 3.11 shows the effect of the proposal on wholesale prices (without interconnection charges). It indicates that:

- peak wholesale prices are driven higher by increased peak demand; and
- shoulder and off-peak wholesale prices are driven lower by increased generation capacity.

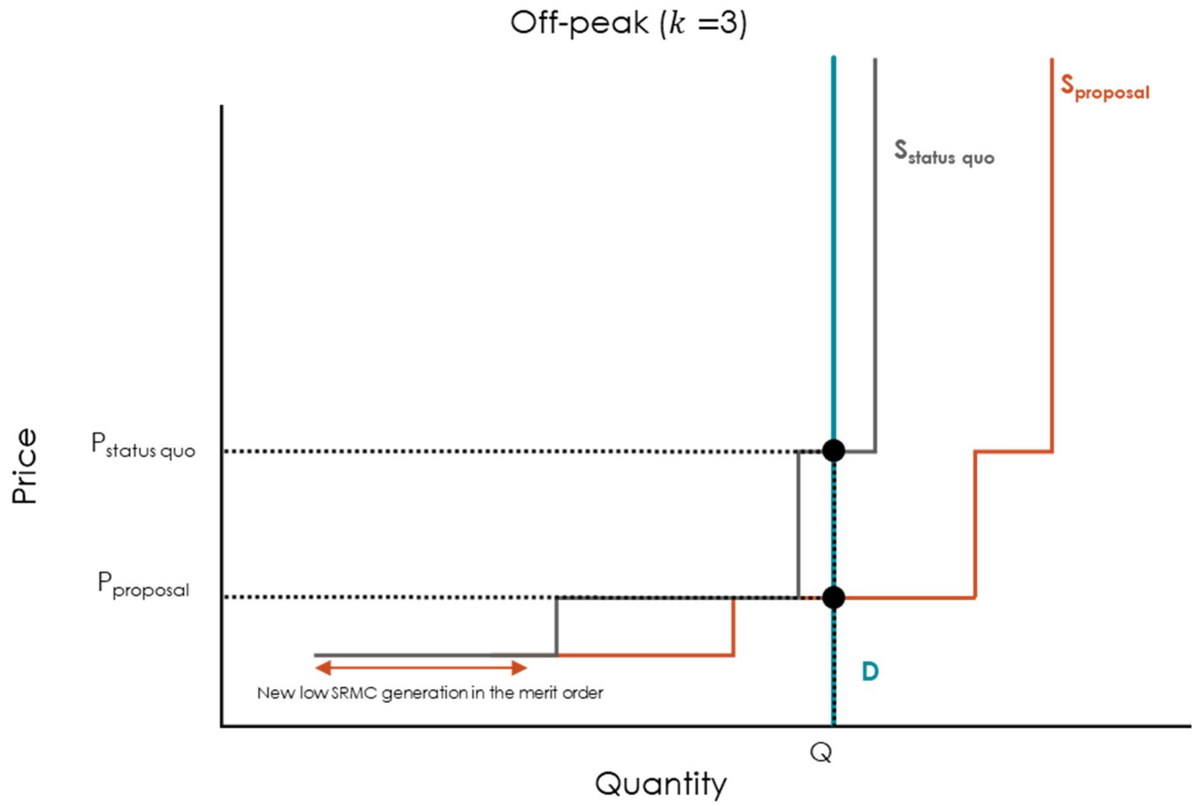
Figure 3.11: Weighted average generation peak, shoulder and off-peak prices, 2019 to 2049

Source: Electricity Authority

The effect of the increased generation capacity under the proposal is to decease prices in the EA's model. This can most clearly be seen with the example of off-peak demand, which remains relatively similar between the proposal and status quo. However, figure 3.7 above shows that off-peak prices under the EA's proposal decrease substantially compared to the status quo.

Figure 3.12 illustrates this effect by showing how an increase in low cost generation pushes the supply curve to the right under the proposal, resulting in a generator with a lower SRMC being the last to be dispatched to meet demand.

Figure 3.12: Increased generation capacity leads to lower shoulder and off-peak prices

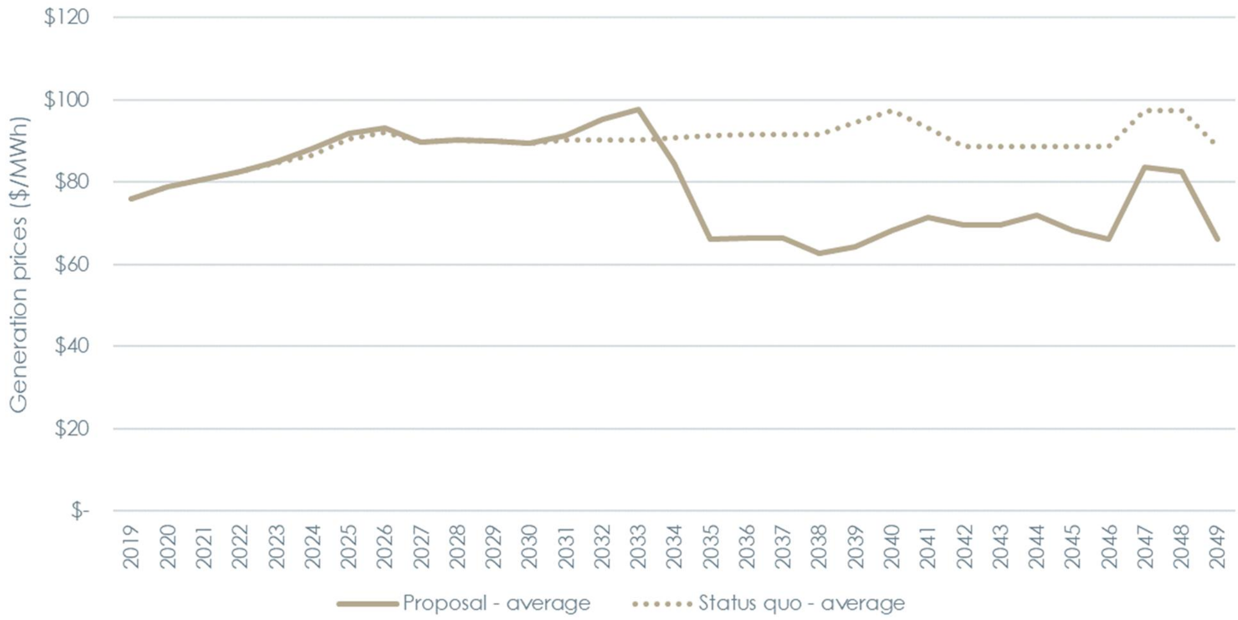


Source: Electricity Authority

Under the EA's modelling framework, the overall effect of the proposal is to decrease weighted average wholesale prices. This is because there is more electricity consumption in the off-peak and shoulder periods than the peak in the EA's model, meaning the effect of the decrease in shoulder and off-peak prices dominates the effect of the increase in peak prices.

Figure 3.13 demonstrates this effect, showing that average wholesale prices under the proposal drop below those under the status quo from 2033.

Figure 3.13: Weighted average wholesale prices, 2019 to 2049



Source: Electricity Authority

3.1.8 Lower wholesale prices will drive further net benefits

The EA estimates that substantial benefits to consumers will arise from the lower wholesale prices across peak, shoulder and off-peak periods amounting to benefits of $2,579 million. The EA values the benefits arising from lower price through two alternative measures of consumer welfare, ie, change in consumer surplus and compensating variation.[59]

The EA's main approach to valuating the benefits of lower wholesale prices is to calculate the change in consumer surplus under the proposal, relative to the status quo. The EA provides an equation for its estimate of change in consumer surplus (ΔCS), ie:[60]

$$\Delta CS = \sum_{i=1}^{4} \left(-x_{it0}(p_{it1} - p_{it0}) - \tfrac{1}{2}(x_{it1} - x_{it0})(p_{it1} - p_{it0}) \right)$$

Applying this formula to a single time of use and for a single year gives:

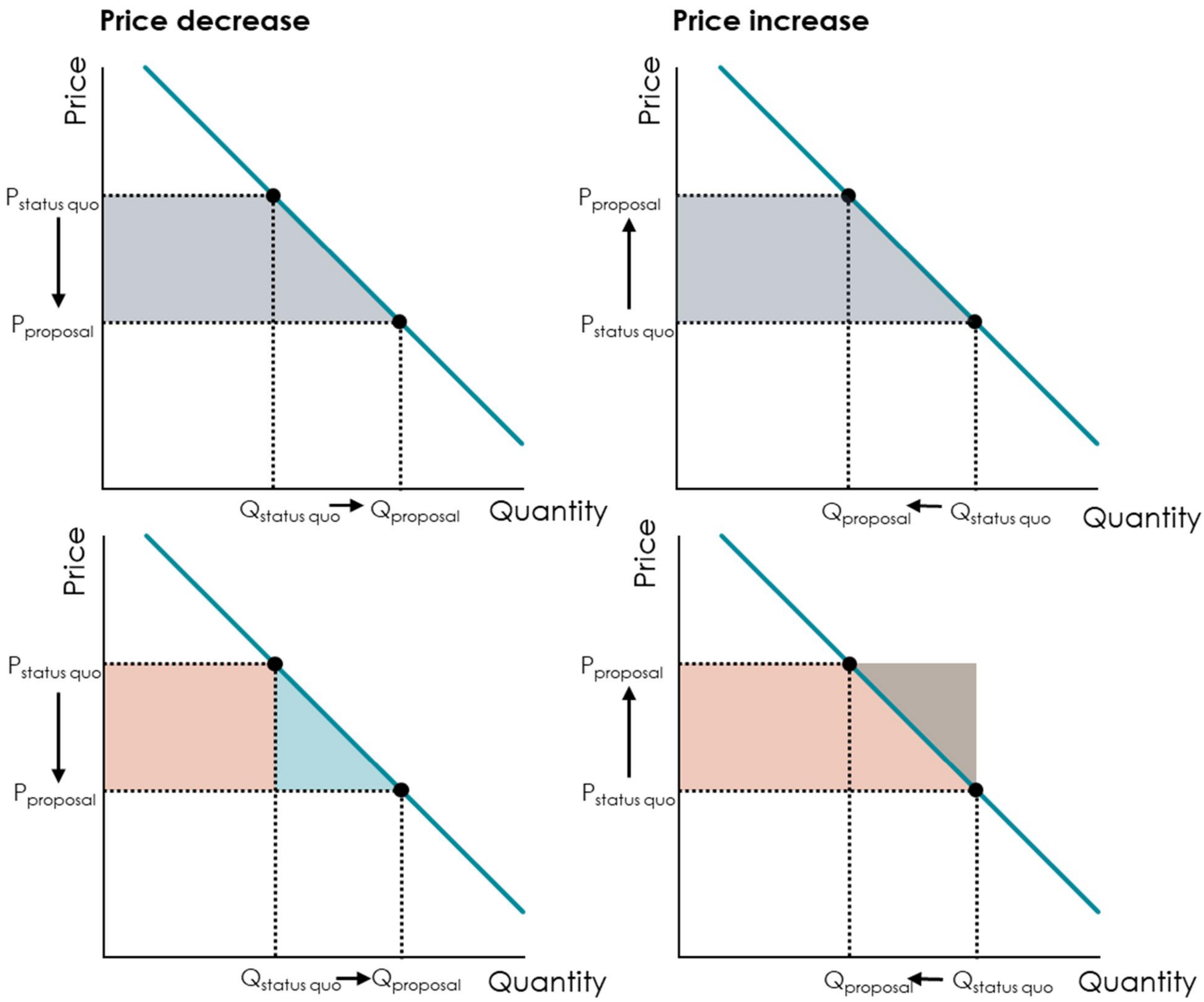
$$\Delta CS = -Q_{status\ quo}\left(P_{proposal} - P_{status\ quo}\right) - \tfrac{1}{2}\left(Q_{proposal} - Q_{status\ quo}\right)\left(P_{proposal} - P_{status\ quo}\right).$$

We illustrate the change in consumer surplus for a single time of use and in a single year in figure 3.14, as the shaded trapezium-shaped region under the demand curve, between the proposal and status quo prices. A price decrease gives rise to an increase in consumer surplus, and correspondingly, a price increase gives prices to a decrease in consumer surplus.

[59] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 34.

[60] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 2.134, p 33.

Figure 3.14: Framework for estimating consumer surplus



The EA's formula calculates the change in surplus:

- when a price decrease occurs, as the sum of the orange rectangle and the blue triangle shown on the left hand side of figure 3.14 above; and
- when a price increase occurs, as the difference between the orange rectangle and the blue triangle show on the right hand side of figure 3.14 above.

The EA applies its formula for change in consumer surplus to the price and quantity data estimated by its grid use model and the 'all major capex' scenario. It calculates the net present value of the change in consumer surplus under its proposal for the period 2022 to 2049.

The EA also calculates consumer benefits arising from lower wholesale prices using compensating variation as an 'alternative approach to test' its estimates of consumer surplus.[61] However, the results of its compensating variation estimation does not contribute to the estimate of the benefits arising from greater grid use of $2,579 million.

[61] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.86.

3.1.9 Higher peak demand drives increased investment in transmission capacity

The EA also models costs arising from greater user of the grid. It assumes that higher peak demand will bring forward investment in transmission capacity and treats this as a cost that must be offset against the benefit associated with greater use of this capacity.[62]

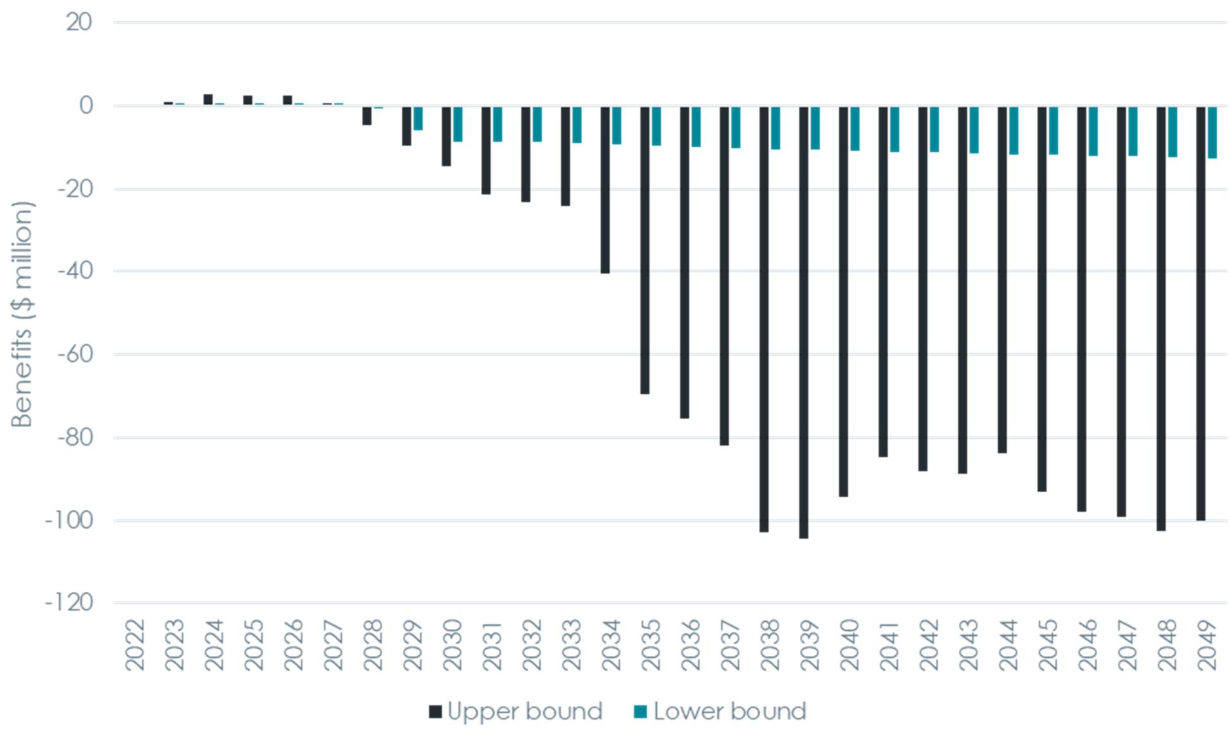
The EA states that it estimates transmission investment brought forward by assuming that the current ratio of forecast transmission revenue to forecast peak demand is maintained. Therefore, as peak demand increases, further grid investment is required.[63]

The EA states that this approach gives rise to present value costs ranging from:[64]

- $67 million, which it calculates under the 'demand major capex' scenario; and
- $421 million, which it calculates under the 'all major capex' scenario.

Figure 3.15 below shows the profile of these costs over time. This profile is consistent with the pattern of peak demand shown in figure 3.7 above. The small initial benefits are associated with a slight decrease in demand relative to the status quo, whereas the greatest costs arise from 2035 as increased consumption in response to lower prices drives increases in consumption in peak periods.

Figure 3.15: Cost of increased investment in transmission capacity, 2022 to 2049



Source: Electricity Authority

[62] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.155.

[63] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.156.

[64] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.157; and Electricity Authority spreadsheet, *Summary costs and benefits.xlsx*, worksheet 'Summary table with ranges'.

However, the EA makes an adjustment to the bounds of this range to exclude unallocated overheads, since it considers that these are not driven by changes in peak demand.[65]

Under the 'all major capex' scenario, the EA estimates that this adjustment gives rise to a reduced cost of bringing forward transmission capacity amounting to $324 million, or a 23 per cent reduction. It applies the same proportionate reduction to give rise to an adjusted cost of $51 million under the 'demand major capex' scenario – in which no effects on battery or generation investment are considered.[66] The central estimate of $188 million is calculated as the mid-point of this range.[67]

3.2 Improved investment efficiencies

The EA considers that the introduction of a 'benefits-based' charge under its proposal, which will allocate the cost of future transmission investments in proportion to the positive benefits that they generate will give rise to more efficient investment in transmission and generation, and improved durability of the TPM framework. It considers that these benefits include:

- $43 million of benefits arising through:
  - deferred transmission investment caused by more efficient decisions by consumers; and
  - deferred transmission investment caused by more efficient decisions by generators;
- $77 million of benefits arising from more efficient grid investment due to increased scrutiny of investment proposals;
- $26 million of benefits arising from reductions in the cost of investing in generation, load and transmission due increased policy certainty; and
- $0.5 million of costs arising from load not locating in regions with recent grid investments.

Figure 3.2 below indicates the breakdown of the benefits that the EA attributes to improved investment incentives.

Figure 3.16: Categories of benefits and costs attributable to greater use of the grid

Source: Electricity Authority

[65] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.158.

[66] Electricity Authority spreadsheet, *Summary costs and benefits.xlsx*, worksheet 'Summary table with ranges'.

[67] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.159.

For three of these benefit categories, the EA attempts to capture the potential spread of benefits through the use of Monte Carlo analysis. Under this technique it:

- establishes a framework for calculating the benefits under each category;
- makes assumptions about the underlying distribution from which uncertain inputs are drawn;
- undertakes a large number of 'trials', in which it uses random values drawn for each of the uncertain inputs to estimate the benefit; and
- makes conclusions about the uncertainty associated with its central estimate of benefit by reference to the distribution of benefits calculated from the trials.

In our description of the EA's approach to estimating benefits, we do not describe its approach to implementing the Monte Carlo analysis and instead focus on the assumptions and steps that underpin the establishment of the framework for calculating benefits. We discuss the EA's use of Monte Carlo analysis in greater detail in section 5.2 below.

3.2.1 More efficient decisions by large loads defer transmission investment

The EA considers that sending more targeted price signals to large loads would give rise to more efficient transmission investment. It assumes that this would occur because:[68]

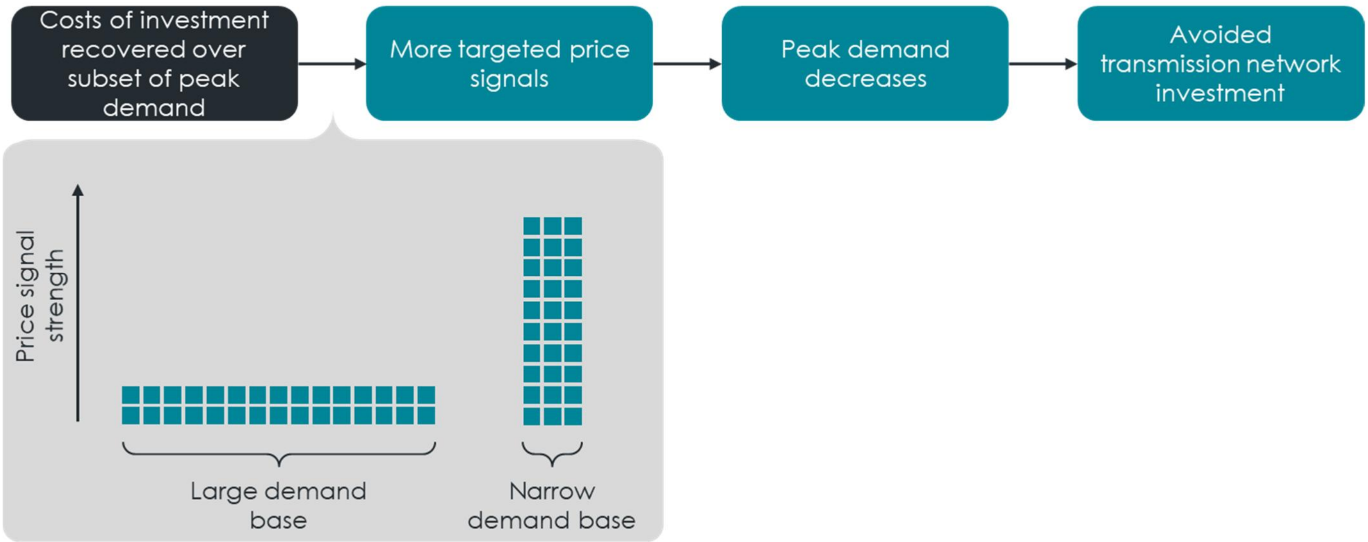
- under the current TPM, these parties do not face the full costs of upgrades to the interconnected grid; whereas
- under the proposed TPM guidelines, they would face the full costs of any required upgrades to the interconnected grid through paying the benefit-based charge.

The EA estimates a benefit associated with this effect by assuming that, under benefit-based pricing:

- the costs of an investment would be recovered over a smaller quantity than otherwise would be the case, giving rise to more targeted (or higher) price signals;
- more targeted price signals will discourage use of the transmission network in peak times; and
- lower peak usage of the transmission network will give rise to transmission cost savings through avoided investment.

[68] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, paras 4.110-4.111.

Figure 3.17: Structure of EA's targeted price signal benefits



We explain how each of these assumptions is implemented in more detail below.

Price signals will be more targeted than previously

The EA assumes that, under benefit-based charging, an average investment would be recovered from a base of 2,464 MW. This compares with total demand based on Transpower forecasts, which is expected to increase from 7,376 MW in 2021 to 8,254 MW in 2033 under the status quo. Thereafter, the EA expects peak demand to grow at 0.84 per cent per annum to 9,436 in 2047.[69]

It follows from these assumptions that the EA assumes that benefit-based interconnection charges would be between 199 per cent and 283 per cent more targeted (or higher) than is currently the case.

However, this effect on users would be muted because new transmission investments only comprise a small part of total electricity charges. The EA estimates that new transmission investments represent 0.84 per cent of total electricity charges, estimated as:[70]

- average incremental transmission investment of $1.08 per MWh delivered over 2015/16 to 2029/30; divided by
- the expected energy price of $109.00 per MWh plus Transpower's regulated revenue of $18.76 per MWh delivered over 2015/16 to 2029/30.

The effect of this assumption is that the more concentrated price signal sent by the benefit-based charge is diluted, so that it is approximately between 1.7 per cent and 2.4 per cent of the electricity price.

More targeted price signals will reduce peak demand

The EA associates these more concentrated price signals with reductions in peak demand of between 1.2 per cent and 1.7 per cent, using an assumed long term price elasticity of -0.74. This amounts to reductions in peak demand, relative to the status quo, of 93 MW in 2021, increasing to 164 MW in 2047, as peak demand increases.

[69] Electricity Authority spreadsheet, '*Investment efficiencies model.xlsx*', worksheet 'Efficient investment', cells D3 and E30:E57.

[70] Electricity Authority spreadsheet, '*Investment efficiencies model.xlsx*', worksheet 'Efficient investment', cell D7.

Reduced peak demand will give rise to transmission savings

The EA assumes that increases in peak demand give rise to additional transmission investment. It calculates this rate of incremental investment expenditure in each year as:

- forecast incremental network investment in that year; divided by
- the change in peak demand between the previous year and that year.

This approach gives rise to estimates of expenditure per additional MW that vary between $178,822 (in 2026) and $2,895,453 (in 2032). The range reflects significant variability in Transpower's forecast incremental network investment over the period to 2035 (after which the EA assumes constant incremental capital expenditure of $20.9 million per year).[71]

The EA assumes that approximately half of the incremental investment in the transmission network is to address growth in demand (rather than growth in generation).[72]

It calculates the benefit associated with more efficient decisions by consumers as:[73]

- the reduction in peak demand that it estimates in each year; multiplied by
- the rate of incremental investment expenditure in that year; multiplied by
- 50 per cent, being the proportion of transmission expenditure required for growth in demand; divided by
- the number of years in its modelling period.

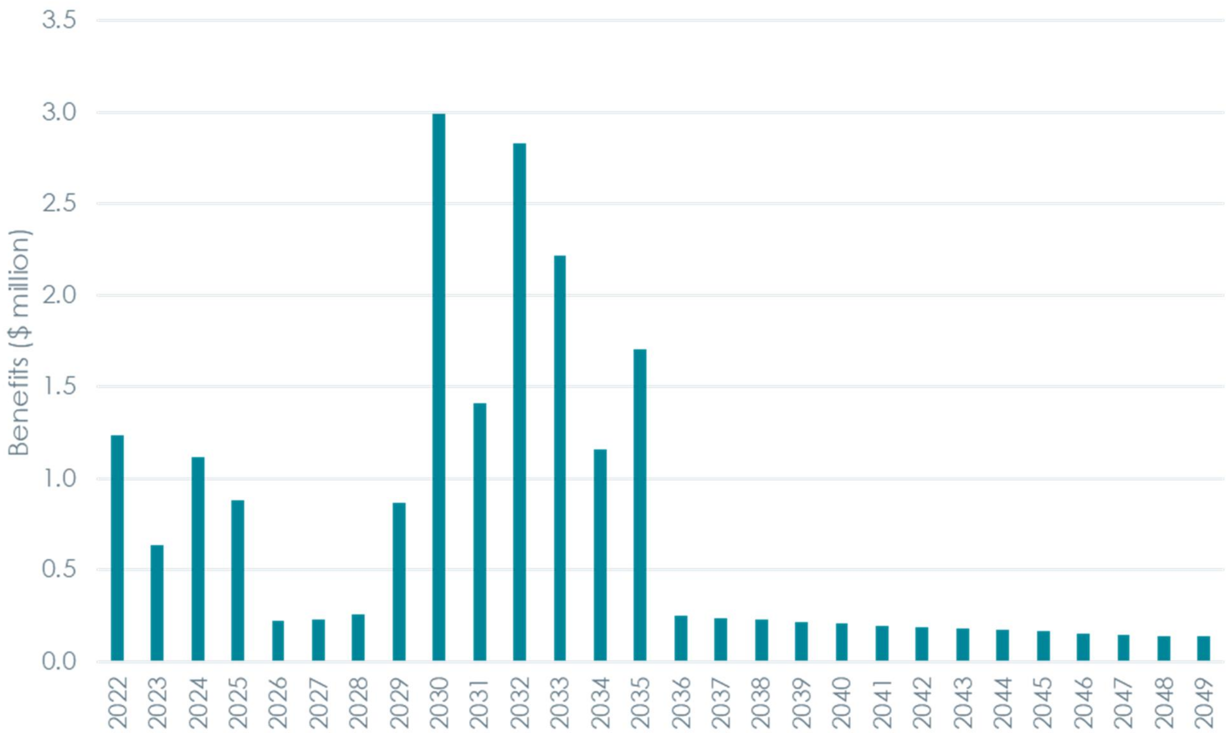
The times series of these benefits are illustrated in figure 3.18 below.

[71] Electricity Authority spreadsheet, '*Investment efficiencies model.xlsx*', worksheet 'Efficient investment', cells F30:F57.

[72] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 79.

[73] Electricity Authority spreadsheet, '*Investment efficiencies model.xlsx*', worksheet 'Efficient investment', cells I30:I57.

Figure 3.18: Reduced peak demand gives rise to transmission savings, 2022 to 2049



Note: This figure represents the EA's spreadsheet modelling. Spreadsheet calculations differ from those set out in the Python code which EA relies on to estimate benefits.

3.2.2 More efficient decisions by generators defer transmission investment

As with its approach to consumption, the EA considers that sending more targeted signals to generators would give rise to more efficient investment in transmission capacity.

It assumes that, under benefit-based pricing:

- relatively less generation capacity would locate in constrained areas of the network; and
- reduced generation capacity in constrained areas of the transmission network will give rise to transmission cost savings through avoided investment.

We explain how each of these assumptions is implemented in more detail below.

More targeted price signals will reduce discourage investment in constrained areas

The EA identifies four nodes of the fourteen that it uses to summarise New Zealand's nodal market which it considers to be constrained. The constrained nodes are labelled 'BEN', 'ROX', 'TWI' and 'WKM'.

The EA calculates the percentage of generation capacity located at these nodes from its grid use modelling:[74]

- under the EA's proposal, under the 'all major capex' scenario; and

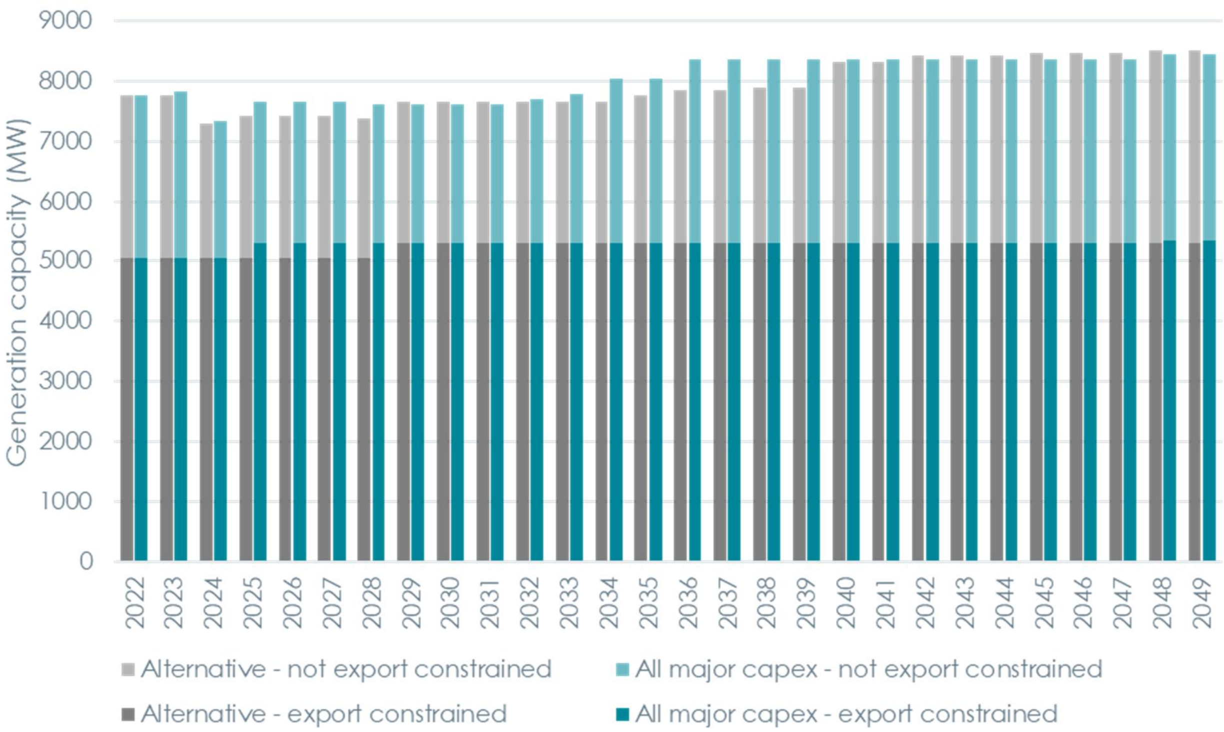
[74] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 82; and Electricity Authority spreadsheet, '*Investment efficiencies model.xlsx*', worksheet 'Generation capacity', cell T3.

- under the 'alternative' scenario, which the EA explains is used as a baseline to avoid measuring generation investment under the RCPD charge.

On average, over 2022 to 2050, the proportion of generation capacity at constrained nodes under the 'all major capex' scenario is 0.5 per cent lower than the 'alternative' scenario.

Figure 3.19 below indicates the breakdown between export constrained and unconstrained areas under the 'all major capex' scenario and the alternative scenario. The charge shows that this result tends to arise from greater growth in generation in areas that are not constrained, under the 'all major capex' scenario.

Figure 3.19: Generation capacity in constrained areas, 2022 to 2049



The EA attributes this change in generation to the effect of its proposed benefit-based charge.

Reduced generation capacity in constrained areas will give rise to transmission savings

The EA calculates the amount of avoided transmission capacity in constrained regions in each year as:[75]

- the total amount of generation capacity in constrained regions in that year;[76] multiplied by
- 0.5 per cent, being the change in generation capacity that the EA attributes to the effect of its proposed benefit-based charge; multiplied by
- 50 per cent, being the proportion of transmission expenditure required for growth in generation capacity.

It computes the benefits associated with avoided transmission investment associated with this capacity as:[77]

- the avoided transmission capacity in constrained regions in each year; multiplied by

[75] Electricity Authority spreadsheet, '*Investment efficiencies model.xlsx*', worksheet 'Efficient investment', cells M30:M57.

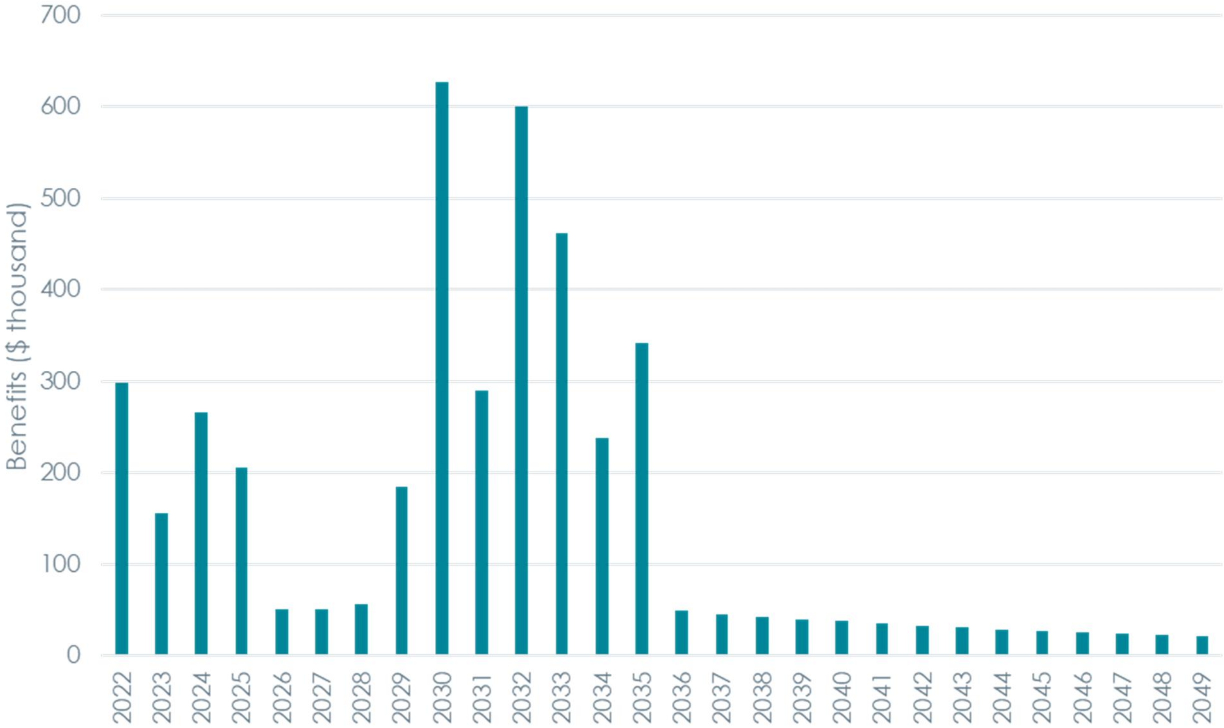
[76] Due to a spreadsheeting error, the EA inadvertently estimates generation capacity using data from three years prior.

[77] Electricity Authority spreadsheet, '*Investment efficiencies model.xlsx*', worksheet 'Efficient investment', cells M30:M57.

- the rate of incremental investment expenditure in that year (which we describe in section 3.2.1 above); divided by
- the number of years in its modelling period.

The time series of these benefits are illustrated in figure 3.20 below.

Figure 3.20: Reduced generation capacity gives rise to transmission savings, 2022 to 2049



3.2.3 Greater scrutiny by stakeholders gives rise to more efficient grid investment

The EA expects its proposal to increase the incentives for beneficiaries of transmission investments to more closely scrutinise proposed investments, which could give rise to benefits in the order of $77 million by:[78]

- enabling lower cost transmission investments or alternatives to such investments; or
- preventing inefficient transmission investments.

The EA considers that this scrutiny would enhance the Commerce Commission's grid approval processes, since customers would have increased incentives to reveal information that more accurately reflected a proposal's net benefits. We understand that the EA has not sought input from the Commerce Commission about the degree of improvement that might feasibly be achieved to its processes.

In the context of the Commerce Commission's consideration of Transpower's capital expenditure program in its draft RCP2 determination, the EA states that reductions of 4.4 per cent were applied to Transpower's proposed enhancement and development capex. However, it does not reference or otherwise explain how it developed this estimate.

[78] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.146.

Dividing Transpower's capital expenditure into six categories, the EA assumes an expected efficiency gain to each category arising from greater scrutiny under benefit-based charges. These efficiency gains range from zero to four per cent, and average 1.9 per cent over Transpower's capital expenditure program between 2022 and 2049.[79]

Table 3.1 below sets out the breakdown of estimated efficiencies that the EA assumes would result from greater scrutiny under the benefit-based charge, and the present value of expenditure (between 2022 and 2049) to which these efficiencies would apply. The table shows that the EA's assumptions give rise to aggregate savings of $76.9 million, over total capital expenditure of $3,997.7 million, in present value terms.

Table 3.1: Breakdown of estimated efficiencies from greater scrutiny

Category	Present value of expenditure	Efficiencies	Present value of efficiencies
Enhancement and development capex (not reviewed by the Commerce Commission)	$51.9 million	4 per cent	$2.1 million
Enhancement and development capex (reviewed by the Commerce Commission)	$121.2 million	2 per cent	$2.4 million
Replacement and refurbishment capex (susceptible to efficiency gains)	$402.8 million	2 per cent	$8.1 million
Replacement and refurbishment capex (not susceptible to efficiency gains)	$1,879.7 million	1 per cent	$18.8 million
Replacement and refurbishment capex (no efficiency gains)	$402.8 million	0 per cent	-
Major capex and listed projects	$1,139.3 million	4 per cent	$45.6 million
Total projects	**$3,997.7 million**	**1.9 per cent**	**$76.9 million**

Source: Electricity Authority

3.2.4 More certain policy environment reduces the cost of investment

The EA considers that its proposal would give rise to benefits for investors in both demand-side and supply-side assets because it would increase the certainty of the policy environment. It states that:[80]

> Apart from the incentive advantages, the Authority regards the benefit-based charge as more likely to be perceived as fair and reasonable than the current approach to spreading the costs of investments across the country.
>
> Over the long-term, pricing arrangements where you 'pay for what you get' would not be contentious (much like the current arrangements for connection charges). As a result, the proposal would lead to more durable transmission pricing arrangements than the existing TPM. A durable TPM is important if the efficiency benefits are to be achieved, and to stop ongoing uncertainty about the TPM. Uncertainty raises the costs of investments.

It assesses the net benefits of this increased policy uncertainty as $26 million, which is calculated as a present value change in total welfare. Underpinning this estimate, it assumes that:

- its proposed TPM guidelines will give rise to a reduction in policy uncertainty;
- the effect of TPM policy uncertainty is to reduce both electricity supplied and electricity demanded, so its proposal will result in an increase in consumption of electricity;
- the combination of these effects gives rise to higher electricity prices; and

[79] The EA has collected forecasts of Transpower's capital expenditure between 2021 and 2035. It estimates annual capital expenditure in each category between 2036 and 2049 as the average of capital expenditure over 2021 and 2035.

[80] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, paras 3.25-3.26.

- the net effect of increased prices and increased quantity is to increase total welfare.

Proposed TPM guidelines give rise to reduced policy uncertainty

The EA assumes that its proposed TPM guidelines give rise to a decrease in policy uncertainty. It assumes that:[81]

- under its proposed TPM guidelines, events of heightened political uncertainty occur once every eleven years; whereas
- under the current TPM guidelines, events of heightened political uncertainty occur once every ten years.

The effect of these assumptions is that its proposal gives rise to a reduction in uncertainty of nine per cent, in relative terms.

The EA assumes that the indexed level of uncertainty is currently 100, so that this amounts to a decrease in the uncertainty index of nine.[82]

Reduced policy uncertainty increases electricity consumption

The EA assumes that policy uncertainty has a negative effect on the quantity of electricity demanded and quantity of electricity supplied. It sets out equations for each of these, by reference to price (*P*), uncertainty (*U*) and income (*M*):[83]

$$Q_d = \alpha_d + \beta_d P + \delta_d U_d + \gamma M$$

$$Q_s = \alpha_s + \beta_s P + \delta_s U_s$$

The EA draws on empirical research that finds that increased policy uncertainty gives rise to reduced investment.[84] The research finds a negative relationship of 8.7 per cent between:[85]

- economic policy uncertainty in the United States, measured by reference to:
  > newspaper articles mentioning uncertainty in connection with the economy and politics;
  > uncertainty about the future expiry of tax code provisions; and
  > dispersion in macroeconomic forecasts of inflation and expenditure; and
- corporate capital expenditure expressed as a proportion of total assets.

The EA assumes that this result applies to the New Zealand electricity industry.

It further estimates the effect of increasing uncertainty on electricity supply taking into account:[86]

- the average ratio of current price fixed capital formation to net capital stock (excluding property) between 1987 and 2017 (10.33 per cent); and
- the average ratio of output to capital stock between 1987 and 2017 (53 per cent).

[81] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 90.

[82] Electricity Authority spreadsheet, *Investment efficiencies model.xlsx*, worksheet 'Durability'.

[83] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equations 36 and 37.

[84] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 90.

[85] Gulen, H & Ion, M, "Policy uncertainty an corporate investments", *The Review of Financial Studies*, 29(3), pp 523-564.

[86] Electricity Authority spreadsheet, *Investment efficiencies model.xlsx*, worksheet 'Durability'.

The product of these two factors gives rise to an estimate of 0.05, which the EA describes as the 'effect of investment on demand and supply', since it assumes the effects on demand are the same as on supply.[87] The EA does not explain whether these measures of output, fixed capital formation and capital stock are whole of economy measures or specific to the electricity industry.[88]

The EA estimates the marginal effect of uncertainty on quantity supplied (δ_s) which it calculates as -2,369, based on:

- the effect of uncertainty on investment derived from the empirical literature, described above; multiplied by
- the effect of investment on demand and supply, described above; multiplied by
- a 'baseline quantity' of just over 47 million MWh; divided by
- a 'baseline price' of $94.5 per MWh.

Reduced policy uncertainty increases prices

The EA expresses its equilibrium price condition as:[89]

$$P = \frac{(\alpha_d - \alpha_s) + \delta_s U_s + \delta_d U_d + \gamma M}{\beta_s - \beta_d}$$

It estimates the slope coefficient of price against uncertainty as -0.005, calculated as:[90]

$$\left(\frac{\delta_s + \delta_d}{\beta_s - \beta_d}\right)$$

Given a reduction of uncertainty of nine per cent, the EA estimates the change in price as a result of its proposal as an increase of 0.05 per cent.[91] Applied to the baseline price of $94.5 per MWh, this amounts to an increase in price of $0.05 per MWh.

Net effect of increased consumption and higher prices is net welfare benefits

The EA calculates net benefits associated with increased durability as the change in total surplus, that is:[92]

$$\Delta TS = \tfrac{1}{2}\left[(P'Q' - PQ) + \left((\bar{P} - P')Q' - (\bar{P} - P)Q\right)\right]$$

Due to its use of Monte Carlo analysis, we cannot describe in exact terms the calculation of the EA's estimate of net benefits. The EA's estimate of $26 million in net benefits is the average of many individual trials, each of which utilise this calculation.

[87] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 90.

[88] Given the long asset lives and capital intensity of electricity supply, we would expect capital expenditure as a proportion of capital stock and the ratio of output to capital stock to be lower than these estimates.

[89] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 39. There appears to be an error in this formula, since the EA has inadvertently added (rather than subtracted) $\delta_d U_d$ in the numerator.

[90] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 43; and Electricity Authority spreadsheet, *Investment efficiencies model.xlsx*, worksheet 'Durability'. This equation is also affected by the error noted in footnote 89 above.

[91] Calculated as 0.005 multiplied by -0.09.

[92] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 45. This is consistent with the formula that it applies in its Python code at *Durability – monte carlo.py*, but different from the approach disclosed in its spreadsheet *Investment efficiencies model.xlsx*.

3.3 Administrative costs arising from the proposal

The EA estimates costs associated with development, implementation and operation of its proposed TPM guidelines across all parties, of $26 million. Figure 3.21 below indicates the breakdown of these costs between each of these functions.

Figure 3.21: Categories of benefits and costs attributable to administrative costs

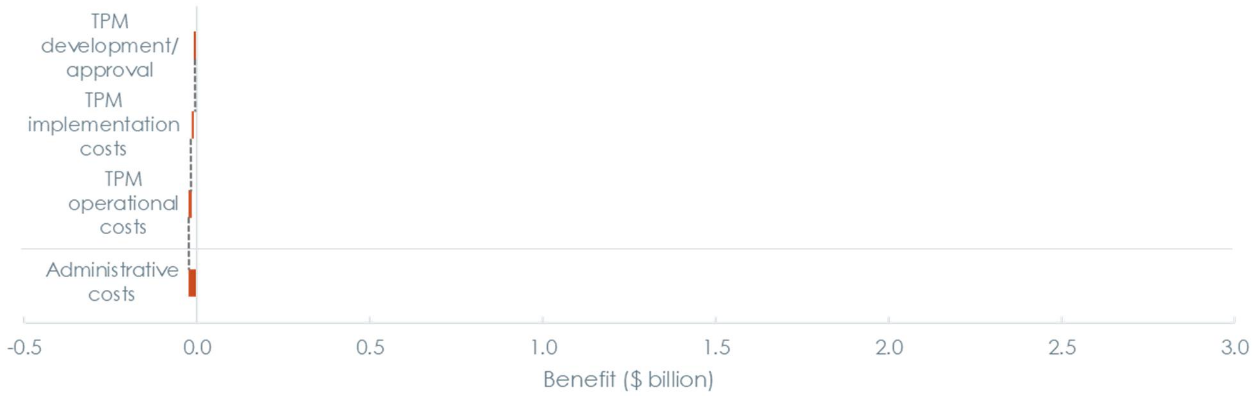


Table 3.2 below summarises the breakdown of the EA's estimates of costs for development, implementation and operation according to the party that is expected to incur these costs. We understand that these costs are arrived at through bottom-up estimates, rather than by reference to the actual costs involved with engagement on TPM processes to date.

Table 3.2: Breakdown of the costs for development, implementation and operation

Party	Development and approval	Implementation	Operation	**Total**
Transpower	$4,080,000	$6,440,000	$8,885,000	$19,405,000
EA	$750,000	n/a	n/a	$750,000
Stakeholders	$1,500,000	$670,000	$370,000	$2,540,000
Legal costs	$1,500,000	$1,500,000	n/a	$3,000,000
Total	$7,830,000	$8,610,000	$9,260,000	$25,695,000

Source: Electricity Authority

The remainder of this section describes the assumptions that underpin these estimates of costs.

3.3.1 Development and approval costs

The EA estimates that the costs of TPM development and approval are $7.83 million, comprised of:[93]

- $4.08 million incurred by Transpower;
- $0.75 million incurred by the EA;
- $1.50 million incurred by stakeholders; and
- $1.50 million of legal costs incurred by the EA, Transpower and various stakeholders.

[93] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 49.

Transpower's costs

The EA estimates Transpower's costs by updating estimates of development costs included in Transpower's submission to the EA's 2016 TPM second issues paper. Transpower commissioned PwC to estimate its development costs, which amounted to $4.28 million under the 'high complexity scenario' that involved implementing the 'full scope' of the EA's 2016 TPM guidelines.[94]

The EA takes the 'high complexity scenario' development cost estimate and reduces it by $200,000. It states that this adjustment is for differences between the EA's 2016 and current proposals.[95] This gives rise to an estimate of $4.08 million, which is not adjusted for inflation (ie, is in 2016 dollars).

EA's costs

The EA develops a bottom-up estimation of its own TPM development costs as $750,000, being the product of:[96]

- the number of additional full time employees required for development (ie, four);
- the cost of an additional full time employee (ie, $250,000 per year); and
- the period over which they would be required (ie, nine months).

Stakeholders' costs

The EA develops a bottom-up estimate of stakeholders' costs, by estimating the costs associated with stakeholders developing submissions to the TPM. The EA:[97]

- defines five 'cost categories', which range from 'negligible cost' to 'very high cost', based on the complexity of the submission;
- estimates the cost of developing a submission for each cost category, which ranges from $0 for negligible cost to $125,000 for very high cost submissions; and
- estimates the number of submissions which would be developed under each cost category, which ranges from 178 for negligible cost to two for very high cost and reflects a total of 300 submissions.

The EA estimates the total cost of stakeholder submissions as $1.50 million, as the number of submissions which would be developed under each cost category multiplied by the cost of developing that category of submission.

Legal costs

The EA estimates that the costs associated with legal challenges that arise in the TPM development process would be approximately $1.50 million 'based on [its] experience with legal challenges to several of [its] decisions over the years.'[98]

3.3.2 Implementation costs

The EA estimates that the costs of TPM implementation are $8.61 million, comprised of:[99]

[94] PwC, *TPM change impact* assessment, July 2016, p 24.

[95] Electricity Authority spreadsheet, *Net costs.xlsx*, worksheet 'TPM development cost estimate'

[96] Electricity Authority spreadsheet, *Net costs.xlsx*, worksheet 'TPM development cost estimate'

[97] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, pp 99-100.

[98] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 5.39, p 100.

[99] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 49.

- $6.44 million incurred by Transpower;
- $0.67 million incurred by stakeholders; and
- $1.50 million of legal costs incurred by the EA, Transpower and various stakeholders.

Transpower's costs

The EA develops Transpower's costs by updating estimates of implementation costs included in Transpower's submission to the EA's 2016 TPM second issues paper. Transpower commissioned PwC to estimate its costs which came to $9.66 million under the 'high complexity scenario' which involves implementing the 'full scope' of the EA's 2016 TPM guidelines.[100]

The EA takes the 'high complexity scenario' implementation cost estimate and reduces it by 33 per cent, an adjustment for difference between the EA's 2016 and current proposals.[101] The produces an estimate of $6.44 million, which is not adjusted for inflation (ie, is in 2016 dollars).[102]

Stakeholders' costs

The EA estimates the costs to stakeholders associated with implementation of the new TPM by summing together bottom-up estimates of costs for transmission customers and distribution businesses. The EA estimates the cost for transmission customers as $0.37 million, based on:[103]

- adopting the assumption that each business would require four weeks of an analyst's time to undertake implementation activities;
- pro-rating the average salary of an analyst (ie, $100,000) for four weeks; and
- multiplying by the number of transmission customers (ie, 48).

The EA estimates the cost for distribution businesses (ie, changes to IT systems) of $0.3 million, based on:[104]

- adopting the assumption that half (ie, 15) of New Zealand's distributors would require upgrades; and
- multiplying this by the 'average' IT system change cost of $20,000.

The EA's total cost estimate for transmission customers and distribution businesses of $0.67 million is the total of these separate cost estimates.

Legal costs

The EA estimates that the costs associated with legal challenges that arise in the TPM implementation process would be approximately $1.50 million.[105]

[100] PwC, *TPM change impact* assessment, July 2016, p 25.

[101] Electricity Authority spreadsheet, *Net costs.xlsx*, worksheet 'TPM implementation cost estimate'

[102] Calculated as $9,661,000 × ⅔ = $6,440,667

[103] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 102.

[104] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 102.

[105] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 5.39, p 102.

3.3.3 Operational costs

The EA estimates that the costs of ongoing administration and operation of the TPM are $9.26 million, comprised of:[106]

- $8.89 million incurred by Transpower; and
- $0.37 million incurred by stakeholders.

Transpower's costs

The EA estimates Transpower's costs by updating estimates of operational costs included in Transpower's submission to the EA's 2016 TPM second issues paper. Transpower commissioned PwC to estimate its costs which came to $1.53 million in the first year of implementation and $0.81 million for each subsequent year under the 'high complexity scenario' which involves implementing the 'full scope' of the EA's 2016 TPM guidelines.[107]

The EA takes the 'high complexity scenario' implementation cost estimate and adjusts for differences between the EA's 2016 and current proposals by:[108]

- reducing the initial implementation operations costs by 25 per cent; and
- reducing ongoing operations costs in subsequent years by 25 per cent.

The EA adds the initial implementation operations costs with the present value of ongoing operations costs over the following 30 years, using a discount rate of 6 per cent. This gives rise to an estimate of $8.89 million, which is not adjusted for inflation (ie, is in 2016 dollars).[109]

Stakeholders' costs

The EA reasons that transmission customers would periodically face incremental costs arising from the reassignment provisions in its TPM (ie, they will request that Transpower reduce the value of a transmission investment).[110] The EA estimates the present value costs to stakeholders as $0.37 million, by:[111]

- adopting the assumption that the reassignment process will be undertaken at 10 years, 20 years and 30 years in the future;
- each reassignment process will involve:
  - two transmission customers asking for reassignment; and
  - 15, 16, or 17 transmission customers making submissions at 10 years, 20 years and 30 years, respectively;
- the cost incurred by a transmission customer asking for a reassignment is $100,000; and
- the cost incurred by a transmission customer making a submission is $10,000.

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[106] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 49.

[107] PwC, *TPM change impact* assessment, July 2016, p 23.

[108] Electricity Authority spreadsheet, *Net costs.xlsx*, worksheet 'TPM ongoing cost estimate'.

[109] Calculated as $\$1,525.000 \times 0.75 + \sum_{i=2}^{30} \frac{\$805,000 \times 0.75}{1.06^i}$.

[110] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 104.

[111] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, pp 104-105.

4. Errors in the EA's conceptual framework

The EA's cost benefit analysis estimates net benefits associated with its proposal of $2,711 billion. These are substantially higher than the benefits that were assessed for the EA's substantially similar 2016 proposal.

However, the benefits derived from the EA's analysis are illusory. The EA's cost benefit analysis is affected by errors that cause it to overstate the benefits and understate the costs of its proposal. The EA's conceptual framework for estimating the benefits under its grid use model, which accounts for the large majority of the net benefits, contains errors such that it:

- overestimates the benefits of its proposal by including a substantial transfer from producers to consumers, whereas it should only include the change in deadweight loss; and
- underestimates the costs of its proposal by excluding the impact of higher peak demand on generation and distribution costs, while capturing only some of the impact on transmission costs.

The concepts behind the EA's grid use model are simple. It estimates net benefits of $2,593 million under its proposal, comprised of:

- increases in consumer surplus, associated with higher consumption and lower prices, of $2,579 million; plus
- reduced inefficient investment in batteries intended to avoid the RCPD charge of $202 million; less
- increased transmission costs due to higher peak period demand bringing forward grid investments.

Transfers between two groups are not benefits to society and do not improve economic efficiency. However, the EA's estimate of benefits associated with greater use of the grid are dominated by transfers from generators to consumers associated with lower nodal prices. In this section we show that the vast majority – about 98 per cent – of the change in consumer surplus that the EA estimates is a transfer, rather than a benefit.

Most of the benefits that the EA claims for its proposal arise from higher peak demand due to the removal of the RCPD charge. However, higher peak demand imposes costs on the electricity industry, since it requires greater capacity to be built in each of the generation, transmission and distribution sectors. The EA's cost benefit analysis underestimates these costs because it:

- assumes incorrectly that the costs of building new generation capacity are incorporated in its analysis;
- ignores altogether the costs of building new distribution capacity; and
- underestimates the costs of building new transmission capacity by averaging across scenarios with lower cost outcomes (while not having regard to those scenarios in its estimates of benefits).

A cost benefit analysis of the EA's proposal should take into account all costs that it causes – whether these arise in the transmission sector or elsewhere in the electricity industry. By way of example, the Commerce Commission's approach to reviewing the efficiency of capital expenditure proposed by Transpower explicitly has regard to 'the capital cost of efficiently meeting demand by means of modelled projects', where these include all non-transmission related assets potentially affected by the option being evaluated.[112]

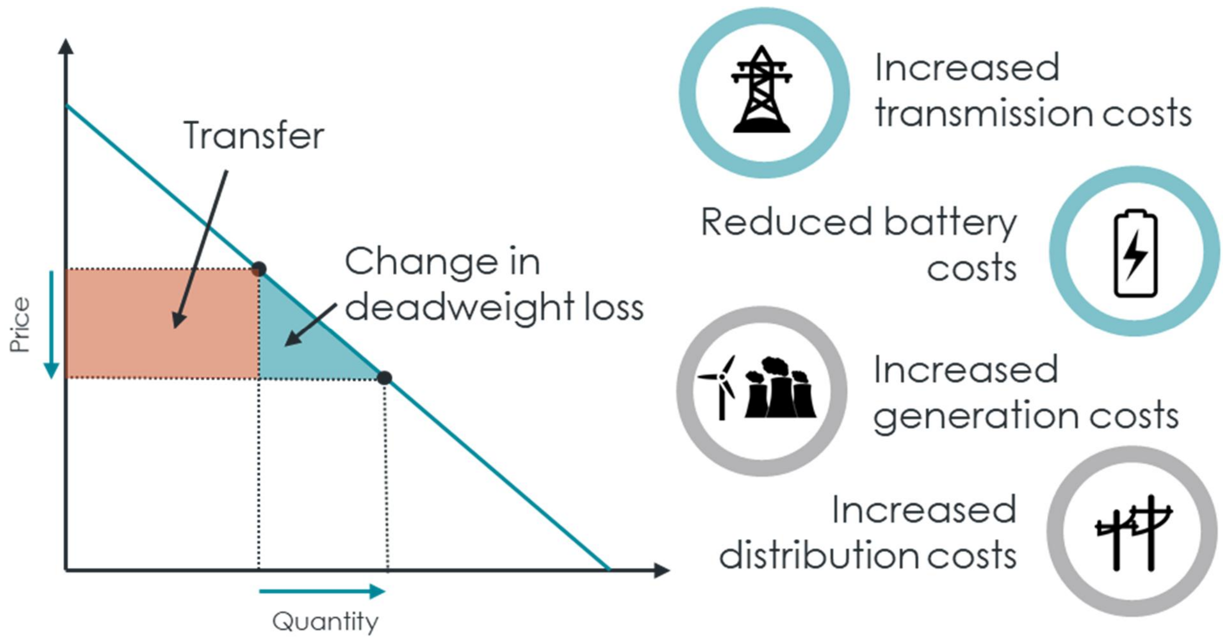
We visually set out these issues in figure 4.1 below. The figure indicates categories of benefits and costs:

- in blue for which the EA *should* and *does* have regard (although not always correctly);

[112] Commerce Commission, *Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination)*, 1 June 2018, pp 65, 70..

- in grey for which the EA *should* but *does not* have regard; and
- in red for which the EA *should not* but *does* have regard.

Figure 4.1: Framework for estimating net benefits in grid use model



With simple corrections, the EA's grid use model can be shown to estimate net costs of $2,303 million, rather than the net benefits of $2,593 million that it claims. The composition of these estimates is set out at table 4.1 below.

Table 4.1: Revised estimates of net benefit from the grid use model

Description	EA's estimate of benefit	Our estimate of benefit
Change in consumer surplus	$2,579 million	$51 million
More efficient investment in batteries	$202 million	$202 million
Increase in transmission costs	-$188 million	-$324 million
Increase in generation costs	n/a	-$1,940 million
Increase in distribution costs	n/a	-$292 million
Total grid use net benefit	**$2,593 million**	**-$2,303 million**

Source: Electricity Authority, HoustonKemp

However, as we explain in more detail in section 5 below, the EA's cost benefit analysis contains numerous errors of assumption and approach. These errors mean that no reliance should be placed on estimates of net benefit (or net cost) that arise from its modelling.

4.1 Change in consumer surplus is largely comprised of transfers

The EA's framework for assessing cost and benefits is focused on the net benefits of its reform for society, rather than any single group. For example, it states:[113]

> …it is possible that the price effect includes some wealth transfers from generators to consumers. That is, if wholesale prices reduce under the proposal, it could be argued that consumers gain at the cost of generators. The [EA] does not take wealth transfers into account in making decisions.

Transfers between two groups are not benefits to society and do not improve economic efficiency. However, the EA's estimate of benefits associated with greater use of the grid is dominated by transfers from generators to consumers associated with lower nodal prices.

The EA's assessment of the benefits associated with its proposal includes the change in consumer surplus that it models as arising from changes to nodal prices that flow from its proposal. We describe its approach to estimating these benefits in section 3.1.8.

We describe in section 5.1.1 why the approach used by the EA to estimate the change in consumer cannot reliably be applied in the context of its cost benefit analysis, because the change in consumption will not represent a shift along the demand curve, as the EA assumes. However, if we set aside this concern and address the EA's estimate on the basis that such a shift is a reasonable representation of the change in consumer surplus, this estimate will overstate substantially the net benefit associated with its proposal.

The effect of including changes in consumer surplus is that the EA's estimate of benefits includes not just changes in deadweight loss, but also changes in transfers between generators and consumers. Figure 4.2 below indicates the change in consumer surplus and shows that this includes:

- a transfer from consumers to generators when nodal prices increase; and
- a transfer from generators to consumers when nodal prices decrease.

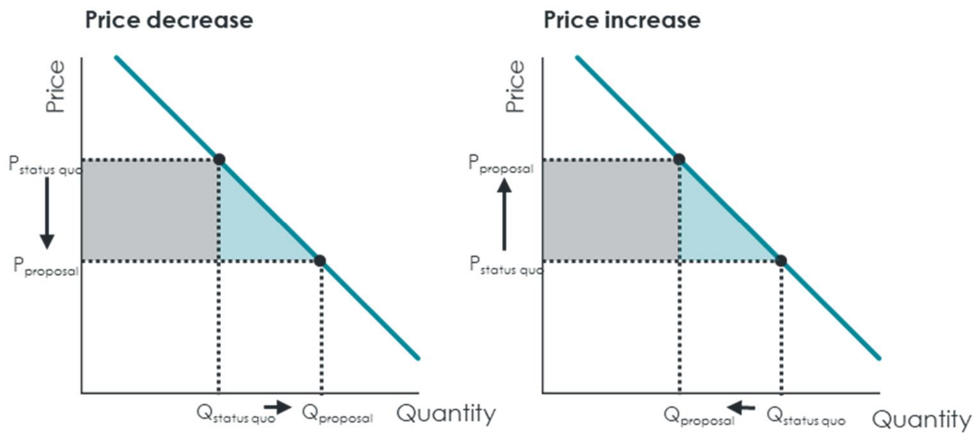
Figure 4.2 also indicates the change in consumer surplus includes:

- an increase in deadweight loss when nodal prices increase; and
- a decrease in deadweight loss when nodal prices decrease.

In figure 4.2, the regions shaded grey indicate a change in consumer surplus due to a transfer and the regions shaded blue indicate a change in consumer surplus from a reduction in dead weight loss.

[113] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.61, p 31.

Figure 4.2: Changes in consumer surplus include transfers



The transfer can also clearly be seen in the EA's formula for the change in consumer surplus. In the context of a decrease in price, the EA's formula separately identifies the transfer as against the change in deadweight loss.

$$\Delta CS = \sum_{i=1}^{4} \Big(\underbrace{-x_{it0}(p_{it1} - p_{it0})}_{\text{Transfer}} \underbrace{- \tfrac{1}{2}(x_{it1} - x_{it0})(p_{it1} - p_{it0})}_{\text{Change in deadweight loss}} \Big)$$

The EA reports that energy prices would be around one per cent lower, on average, under its proposal as compared to the status quo. In the context of a market in which approximately $4.2 billion of electricity was sold in 2018,[114] it is hardly surprising that the present value of an increase in consumer surplus associated with a reduction of price of this magnitude would be substantial. The EA estimates this increase in consumer surplus as $4.37 billion under its base case 'all major capex' scenario.

4.1.1 Almost all the EA's estimate of benefit is a transfer

It is also straightforward to see that the vast majority of the increase in consumer surplus resulting from the change in prices is a transfer.

The EA estimates the price impact of its reform as approximately one per cent. However, its model outputs suggest that, on a volume weighted basis, the present value of average wholesale prices under the proposal are 3.19 per cent lower than under the status quo.[115]

Demand for electricity is understood to be inelastic, so the impact on quantity demanded will be less than the price change. It follows that the change in deadweight loss associated with a 3.19 per cent change in price should be less than 1.60 per cent of the transfer since the change in consumer surplus can be expressed in terms of the relative change in prices and quantities, as shown below:

$$\Delta CS = -Q(\Delta P) - \tfrac{1}{2}(\Delta Q)(\Delta P) = -QP\left[\left(\frac{\Delta P}{P}\right) + \tfrac{1}{2}\left(\frac{\Delta P}{P}\right)\left(\frac{\Delta Q}{Q}\right)\right]$$

[114] Estimated from demand data and price data sourced at the Electricity Authority's website, accessible at www.emi.ea.govt.nz/r/1v1rx and www.emi.ea.govt.nz/r/4413r.

[115] Calculated using outputs from the EA's 'all major capex' base scenario.

The EA cites a long run elasticity of demand for electricity of -0.74.[116] If this estimate were accurate then it suggests that, from a total increase in consumer surplus of $4,370 million:

- the transfer from generators to consumers must be at least $4,319 million;[117] and
- the reduction in deadweight loss can be at most $51 million.

The simple calculations above demonstrate that almost all – about 99 per cent – of the change in consumer surplus is likely due to a transfer from generators to consumers, with only a small residual potentially representing an improvement in efficiency.

4.1.2 Model averaging does not mitigate this concern

The EA notes that taking into account the change in consumer surplus that include the effects of generation investment on wholesale energy prices is not likely to be a reasonable approach since this may contain a mix of efficiency effects and transfers, which it claims are difficult to disentangle. The EA explains: [118]

> …the [EA] considers it should place less reliance on the potential benefits from this generation investment and energy price effect, compared to the allocative efficiency effects that would come about directly from the proposed change in transmission prices.

Its preferred approach to addressing this is to present as its 'main estimate' a change in consumer surplus estimate calculated as the mid-point between:[119]

- $4,370 million, which includes modelled reduction in energy prices; and
- $50.8 million, which holds energy prices constant.

The EA justifies its model averaging on the basis that:[120]

> Model averaging is a common adjustment when there is uncertainty about the best approach. The Authority considers this to be an appropriate adjustment in this case too.

In our view, this position is not supportable, given that there such a substantial difference between the estimates and that basic economic principles can be used to disentangle the transfer from the efficiency gain.

The EA does not reference the statistical theory that supports its preferred model averaging period. We are aware of propositions in other contexts that adopting a weighted average of two estimators may give rise to an estimate that has lower mean square error than either estimator, even if one of those estimators is biased.[121] However, in relation to that theory, it is relevant to note that:

- this approach does not support the simple averaging of two estimators where one is understood to have substantial bias – instead, the weight of the biased estimator would be reduced commensurate with its bias; and
- this approach does not support using a biased estimator in circumstances in which it is possible to correct or reduce this bias – an adjustment that would further improve mean squared error.

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[116] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.115, p 40.

[117] Calculated as $4,370 / (1 + 0.5 x 0.74 x 0.0319).

[118] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.100, p 38.

[119] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, paras 4.99-4.100; and Electricity Authority spreadsheet, *Summary costs and benefits.xlsx*, worksheet 'Summary grid use model'.

[120] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.100.

[121] This argument has been put by Dr Martin Lally for the Commerce Commission in his approach to considering how the tax-adjusted market risk premium should be calculated. See Lally M, *Review of submissions on the cost of debt and the TAMRP for UCLL and UBA services*, 13 June 2014, pp 23-25.

It follows that the EA should not adopt an estimate of benefits as the simple average of $4.37 billion and $50.8 million. This approach does not significantly reduce the concerns about the extent to which it captures transfers in its estimate of benefits. Rather, the effect of the averaging process is to reduce the share of transfers in the EA's estimate of the change in consumer surplus from 99 per cent to 98 per cent.[122]

In our view, absent other concerns with the EA's modelling (which we discuss in section 5.1 below), it would be reasonable to conclude that the benefit arising from reduced deadweight loss fall within a range that is bounded above by about $51 million, consistent with the approximate upper bound of benefits from its modelling.

4.2 Increases in generation costs are not taken into account

The EA's grid use model estimates that increased use of the transmission network at peak times under its proposal gives rise to an additional $1,940 million of investment in new generation facilities. These should be accounted for as costs associated with the EA's proposal.

However, the EA does not factor these additional generation costs into its cost benefit analysis, stating that it believes that the generation sector is competitive:[123]

> The CBA does not include any costs for generation investment brought forward. This is because 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 is not a valid basis for excluding the costs of additional generation. The costs of investing in new generation are costs to society to which the EA must have regard in assessing the costs and benefits of its proposal, regardless of the competitiveness or otherwise of the generation sector.

In the context of a competitive generation sector, it might generally be expected that the revenues earned by new entrants would be similar to their costs. However, this does not occur in the EA's grid use model. We explain in section 5.1.2 below that errors in the EA's modelling give rise to a significant reduction in the profitability of the generation sector. This in turn causes the wholesale price to collapse due to the quantity of new generation capacity flooding the market – a collapse that would not have occurred in a competitive market.

It follows that the EA's modelling framework proposes to:

- take into account the benefits associated with this decrease in price, consisting of reduced deadweight losses;[124] but
- not take into account the costs that give rise to this decrease in price, consisting of additional investment in generation.

The inconsistency between these assumptions is self-evident. It cannot be reasonable to capture the benefits associated with the influx of generators that the EA models without also taking into account the costs. The correct approach is that all benefits and all costs associated with the EA's proposal should be taken into account in the analysis.

4.3 Increases in distribution costs are ignored

The EA does not take into account the increased costs of providing distribution services that are associated with increases of peak demand that it assesses in its grid use modelling.

[122] Estimated as 1 - $50.8 / $2,579.

[123] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.162.

[124] Although we explain in section 4.1 above that the EA erroneously also includes in its estimate of benefits the transfers from producers to consumers associated with this decrease in price.

This is a material error in its assessment of the costs and benefits of its proposal. Higher distribution costs follow as a consequence of the EA's proposed reform and should be taken into account along with other costs and benefits of its proposal. It is not correct for the EA to assume away these costs by stating that its cost benefit analysis 'focuses' on transmission.

Under simple assumptions as to the LRMC of distribution network capacity, we estimate that the additional costs of providing distribution network capacity to serve increased peak demand under the EA's proposal lies in a range from $106 million to $428 million.

We set out the basis for these views in more detail below.

4.3.1 Assessment of the costs of the EA's proposal must include increased distribution capacity

The EA states that it does not take into account the increased costs associated with providing distribution network services associated with the benefits of increased use of the transmission network:[125]

> The CBA does not include any costs for distribution network investment brought forward. This is because the focus of the CBA is transmission, not distribution. Accordingly, we have not evaluated either the incremental costs or the incremental benefits associated with the distribution network.

This assumption is not tenable. We show at figure 3.7 above that, under the EA's assumptions, average demand in the peak period increases by up to 1,300 MW under its proposal as compared to the status quo. Increases in peak demand of this magnitude can reasonably be expected to have substantial impacts on the costs of providing distribution network services, since distribution businesses will likely need to undertake capacity augmentation to meet increased demand.

Increased use of the transmission network at peak times gives rise to benefits to users of the transmission network. However, it also imposes costs in terms of the increased investment in capacity that generation, distribution and transmission facilities must provide in order to service this demand.

It is not correct for the EA to assume away distribution costs by stating that its cost benefit analysis 'focuses' on transmission. This is no more reasonable than a view that its analysis should focus only on benefits, rather than costs. Distribution costs follow as a direct result of the increased demand that the EA models as following from its reform and giving rise to benefits in the form of reduced deadweight loss. These increased costs should be incorporated into the analysis.

Distribution networks are regulated entities. Additional capital expenditure that they undertake to meet increases in peak demand is rolled into their regulated asset bases and recovered from customers in higher electricity prices. The EA's assumption that it can ignore distribution costs effectively means that it is choosing to ignore a large part of the impact that its proposal would have on the costs of supplying electricity, and so on the customers of electricity. It is not possible to reconcile this approach with the EA's statutory objective.

4.3.2 Increased distribution capacity required under the proposal likely imposes significant costs

Under the EA's 'all major capex' scenario, the proposal results in an average increase in average peak demand of 654 MW from 2022 with a maximum incremental increase of 1,322 MW in 2040 over the status quo. We show these effects in figure 4.3 below.

To estimate the extent to which the incremental increase in demand under the proposal passes through to the maximum annual peak demand of New Zealand distribution networks on average, we conservatively assume that:

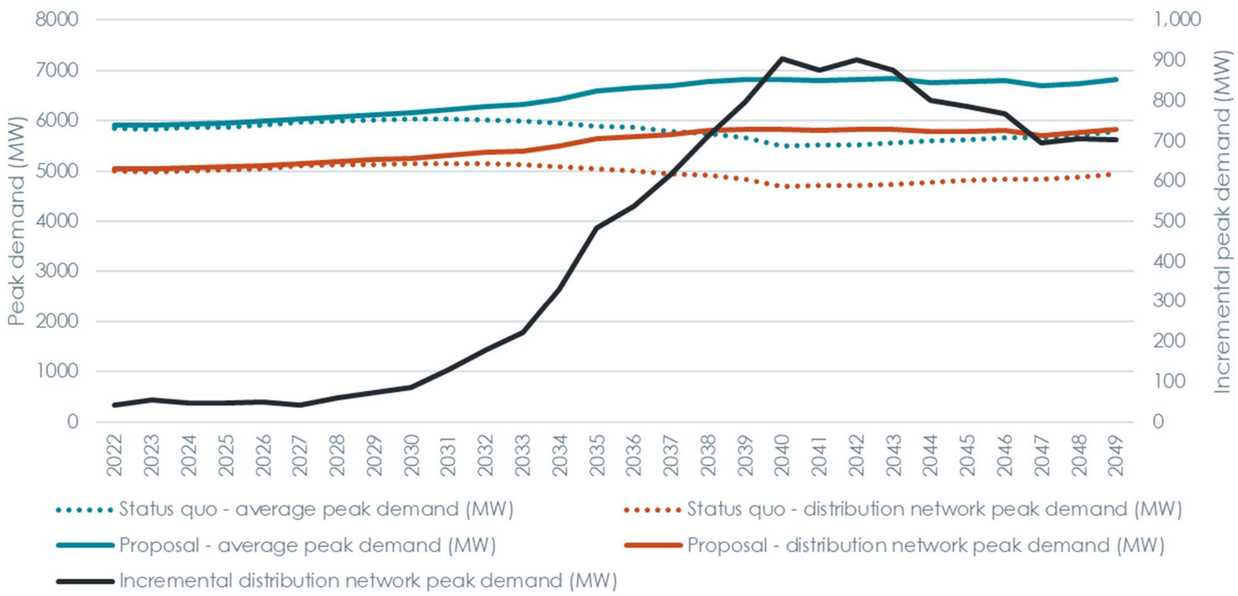
- distribution network peak demand has an 80 per cent **coincidence** with transmission peak demand on average;

[125] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.160.

- the **maximum annual peak demand** of distribution networks is 120 per cent of the annual average peak demand; and
- the **share of peak demand** attributable to distribution networks, rather than other types of transmission connected customers, is 89 per cent.[126]

Under these assumptions, the proposal gives rise to an average increase in distribution network annual peak demand of 447 MW from 2022 with a maximum increase of 904 MW in 2040 over the status quo.

Figure 4.3: Changes to distribution network demand under the EA's proposal



Source: Electricity Authority and HoustonKemp analysis

We form a wide range of LRMC estimates for New Zealand distribution networks by reference to the costs reported by Australian networks in the context of their tariff structure statements.[127] The Australian distribution network LRMCs used are set out in table 4.2 below.[128]

[126] Electricity Authority spreadsheet, *'Proposal impacts modelling.xlsx'*.

[127] NEM Distribution Network current Tariff Structure Statements, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs. We assume a power factor of 80 per cent and an exchange rate of 1.05 NZD per AUD.

[128] The Australian LRMCs are expressed on the basis of LRMC for incremental demand for a customer connected at a particular voltage level. For example, a low voltage customer has a higher LRMC than an HV customer because its LRMC estimate reflects the long run costs of both low voltage and high voltage assets that it uses.

Table 4.2: Australian distribution network LRMCs

Distribution network	Unit	Low voltage residential	Low voltage commercial	Low voltage	High voltage	Sub-transmission
AusNet Services	($/kW per year)	93.17	93.17		25.83	16.89
CitiPower	($/kW per year)	98.91	111.88		70.67	26.04
Powercor	($/kW per year)	101.43	116.66		80.85	10.29
United Energy	($/kW per year)	67.97	79.36		48.94	9.83
Essential	($/kW per year)			150.62	121.73	14.06
Ausgrid	($/kW per year)			59.01	37.80	6.72
Endeavour	($/kW per year)			95.87	8.51	8.19
Energex	($/kW per year)			136.58	130.03	63.38
EvoEnergy	($/kW per year)	116.55	55.65		12.60	
Power and Water Corporation	($/kW per year)			252.00	119.70	
SA Power Networks	($/kW per year)	116.55	116.55		84.00	23.10
TasNetworks	($/kW per year)	147.00	140.70		93.45	
Jemena	($/kW per year)	124.95	110.25		52.50	52.50

Source: Australian electricity distribution businesses

We acknowledge that Australian estimates of LRMC are an imperfect proxy for New Zealand distribution network costs. To mitigate against this concern, we have adopted a very wide range of LRMC values from the Australian estimates, ranging from:

- a **low estimate** of LRMC of $29 per kW (the lower quartile);
- a **mean estimate** of LRMC of $80 per kW; and
- a **high estimate** of LRMC of $117 per kW (the upper quartile).

In our view, the bottom end of this range is likely to substantially underestimate the average LRMC of a distribution network since it is derived from the LRMC for a high voltage customer, which does not include any of the costs of low voltage assets.

We note that Orion's estimates of long-run average incremental cost (which is how most estimates of LRMC are developed in Australia) is $104 per kW per year for general connections and $96 per kVA for major customers connections.[129] These estimates are aligned with, and at the upper end, of the range of cost estimates that we present above.

Applying our estimate of the average LRMC of New Zealand distribution networks to the incremental increase in distribution network annual peak demand as a result of the proposal, and using a discount rate of 6 per cent, we find that:

- under the **low estimate** of the average LRMC of New Zealand distribution networks the proposal leads to:
  - average annual present value incremental distribution network costs of $3.80m; and
  - maximum annual present value incremental distribution network costs of $7.70m in 2040;
- under the **mean estimate** of the average LRMC of New Zealand distribution networks the proposal leads to:

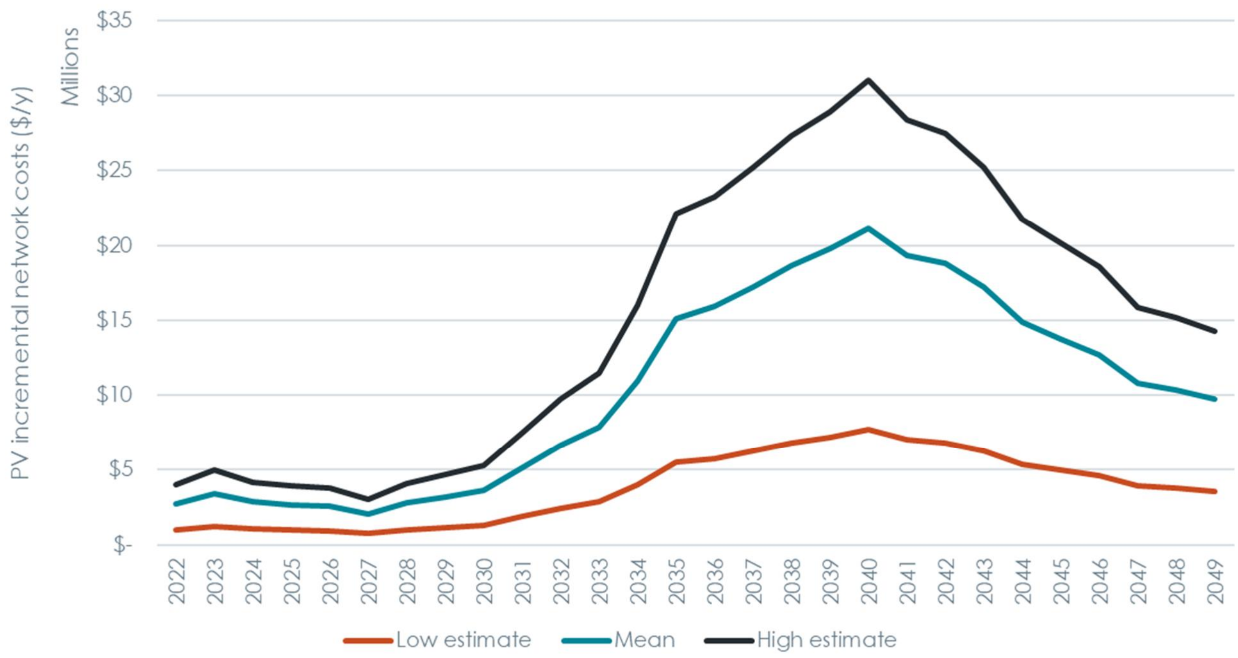
[129] Orion, *Methodology for deriving delivery prices*, 22 February 2019, pp 28 and 34.

> average annual present value incremental distribution network costs of $10.43m; and
> maximum annual present value incremental distribution network costs of $21.16m in 2040;

- under the **high estimate** of the average LRMC of New Zealand distribution networks the proposal leads to:
  > average annual present value incremental distribution network costs of $15.27m; and
  > maximum annual present value incremental distribution network costs of $30.98m in 2040.

Figure 4.4 below shows the present value of annual incremental distribution network costs as a result of the proposal from 2022 until the end of the modelling period.

Figure 4.4: Present value annual incremental distribution network costs, 2022 to 2049



Source: HoustonKemp analysis

Based on this analysis, we find that the net present value of incremental annual distribution network costs as a result of the EA's proposal under the 'all major capex' scenario is:

- $106m under the **low estimate** of average New Zealand distribution network LRMC;
- $292m under the **mean estimate** of average New Zealand distribution network LRMC; and
- $428m under the **high estimate** of the average New Zealand distribution network LRMC.

We consider that the additional costs of providing distribution network capacity to serve increased peak demand under the EA's proposal is likely to lie in a range from $106 million to $428 million.

4.4 Increases in transmission costs are underestimated

We explain in section 3.1.9 that the EA assumes that increases in peak demand brings forward transmission investment. This is an appropriate assumption – along with the costs of generation and distribution investment, the costs of transmission investments driven by increases in peak demand should be taken into account.

However, the EA's central estimate of $188 million is inappropriately calculated as the average of two alternative estimates of increased transmission investment under two scenarios, being:

- $324 million under the EA's 'all major capex' scenario; and
- $51 million under the 'demand major capex' scenario.

The EA employs 14 scenarios in its grid use model, of which its central scenario is the 'all major capex' scenario. For example, its central estimate of change of consumer surplus draws on the 'all major capex' scenario, which takes into account extensive investment in batteries under the status quo and generation under the proposal – assumptions that we describe in more detail in section 4 below. By contrast, the 'demand major capex' scenario does not take into account these effects.

Against this backdrop, we do not consider it reasonable for the EA to adopt a central estimate for transmission investment brought forward that averages across these scenarios. The 'all major capex' scenario provides central estimates for the key benefits that the EA claims for its grid use model. To be consistent with this, the EA should also adopt central estimates for costs from the same model.

By way of example, the EA claims increased consumer surplus of $2,579 million and reduced battery investment of $202 million under the 'all major capex' scenario. However, under the 'demand major capex' scenario, these benefits are $83 million and $0 million respectively.[130] Yet, the EA does not propose to estimate its benefits as the simple average of results under these scenarios.

Consistent with its reliance on the 'all major capex' scenario as its central estimate, the EA should utilise $324 million as its central estimate of transmission investment brought forward under its proposal.

[130] Electricity Authority spreadsheet, *Summary costs and benefits.xlsx*, workbook 'Summary grid use model'.

5. Further errors of assumption and approach

In addition to the errors in the conceptual framework that we identify in section 4 above, the EA's cost benefit analysis also incorporates material errors of assumption and approach in the implementation of that framework.

Of greatest consequence, we note that:

- the EA's modelling of battery investment, generation investment and wholesale market prices are affected by substantial errors that cause the EA to overestimate battery investment under the status quo and generation entry under its proposal;
- the EA relies on an unreliable basis for estimating the change in consumer surplus which cannot be applied validly given the shifts of demand curves that it assumes;
- our review of the EA's demand modelling suggests that there is little reason to believe that the models that the EA uses to estimate elasticities give rise to robust and statistically significant estimates;
- the modelling of investment efficiencies assumes that the benefit-based charge sends a cost-based pricing signal, which is not a component of the EA's proposal; and
- the calculation of benefits associated with increased scrutiny and increased durability of the proposal are entirely unreliable since they depend on assumptions which cannot be confirmed by reference to facts.

In our view, the number and nature of the errors that affect its analysis mean that no reliance can be placed on the results of the EA's modelling.

5.1 Greater use of the grid

Under the EA's proposal, the RCPD charge will be removed and interconnection costs will be recovered through fixed charges. The EA considers that this change will result in more efficient utilisation of the transmission grid, reflected in increased use of the grid during peak periods.

The EA estimates net benefits associated with greater use of the grid of $2,611 million, falling into a range from $167 million to $6,140 million. At section 3.1 above, we explain the assumptions and steps that underpin these estimates.

We explain in section 4 above that these estimates are vastly overstated and reflect the outcomes of an analytical framework that does not correctly capture the benefits and costs associated with greater grid use. In addition to these concerns, the EA's implementation of its analytical framework is affected by further errors, such that its estimates of benefits:

- include the avoided costs of substantial inefficient investment in grid-scale batteries under the status quo, based on a framework for analysis that does not capture the key economic factors that influence decisions to build batteries;
- reflect reductions in wholesale prices based on a rule for generation entry that is not forward-looking, resulting in outcomes that would give rise to significant losses for generators under the EA's proposal;
- rest on a framework for assessing consumer surplus that cannot reliably be applied in the circumstances; and
- rely on elasticity estimates sourced from demand modelling that is of uncertain reliability.

5.1.1 Benefits assume uneconomic investment in batteries in the status quo

We explain in section 3.1.5 above that the EA's modelling assumes that there will be a surge of inefficient investment in batteries under the status quo, amounting to additional investment of $202 million in present value terms. This amounts to an assumption that over 3,000 MW of battery capacity would be installed under the status quo for the purpose of avoiding transmission charges.

The purpose of modelling is to capture the essence of key relationships that transform inputs into outputs. Making simplifying assumptions is a necessary requirement for modelling. However, in making simplifications, it is important that essential elements of the fundamental relationship that is intended to be captured are retained, and that the assumptions do not themselves simply determine the results of the modelling. The EA's approach to modelling battery investment falls into this error because:

- its EA's modelling framework is incapable of capturing the declining profitability of marginal investment in batteries; and
- the battery capacity chosen by the model does not reflect an optimal economic decision determined by the model but is the result of a poorly justified relationship imposed within the model and driven by an assumed parameter value.

The result of these errors is that the EA's grid use modelling is likely to overstate substantially the extent to which battery investment would be incentivised under the status quo.

Investment case for batteries declines rapidly with increasing investment

The economic opportunity for a battery involves arbitrage between periods with low and high prices. It follows that it is reasonable to assume that recovering interconnection costs at peak times may give rise to incentives for transmission users to invest in batteries to avoid transmission charges.

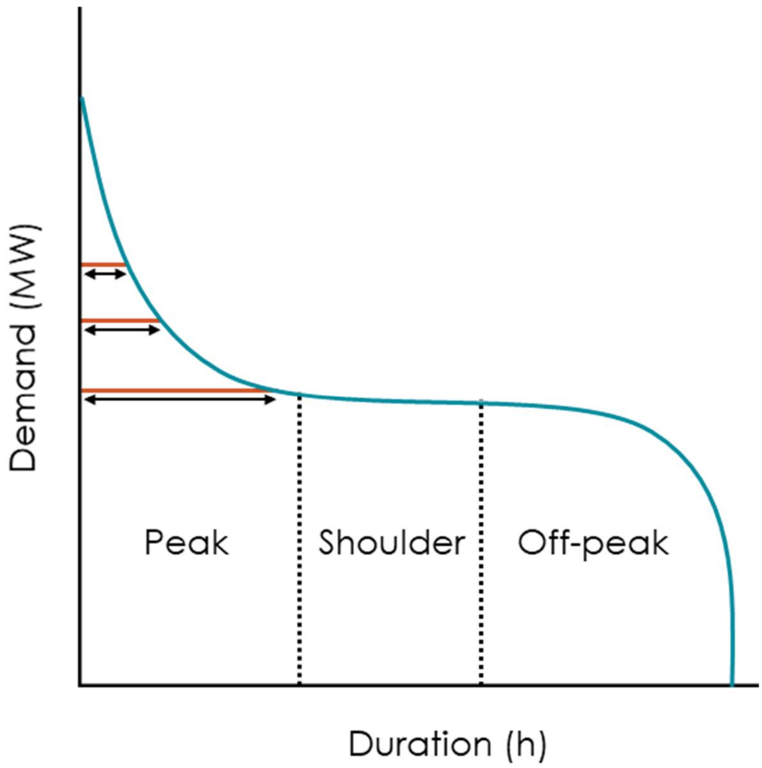
Under the current TPM, RCPD charges are recovered across the 100 highest peaks of regional coincident demand in a year. It follows that batteries that aim to avoid these charges will operate so as to:

- charge during periods of low wholesale prices; and
- discharge during periods in which the RCPD charge is likely to apply.

Investment in batteries would be expected to give rise to 'shaving' of peak load, reducing the opportunities for further battery investment. Figure 5.1 shows a stylised diagram in which batteries are used to shave load from a load duration profile. Even under these idealised assumptions, in which batteries are assumed to discharge when required, the opportunities for battery investment decline with additional installed battery capacity.

Since the RCPD charge is applied to 100 half hour periods with the highest regional demand, the optimal strategy in a peak period is to avoid the transmission charge by reducing demand up to (but no further) than the point at which the charge could no longer apply to that period. This provides the greatest benefit for the very highest peak, and less benefit for lower peaks. As the process continues, load in a greater number of periods must be reduced to achieve a reduction in the transmission charge. This means that the marginal benefit associated with each battery declines increasingly steeply with each additional investment.

Figure 5.1: Investment in batteries shave peak demand from the load duration profile



Source: HoustonKemp

EA's modelling framework does not capture economic value of batteries

The EA's modelling does not correctly capture the profitability of investment in batteries. Under the status quo, it assumes that consumers invest in batteries whenever net revenues are greater than capital costs. However, once this threshold is reached, the amount of battery investment in a given year is the greater of 1 MW and equation 29 set out in the EA's technical appendix:[131]

$$r_t \cdot \eta_b \cdot \frac{q_{t,k=1}}{q_{t,k=1} + MW_{t-1}}$$

This relationship has some properties that might be consistent with those that would be expected of a battery investment process. In particular, it decreases with existing battery capacity, increases with peak demand, increases with net revenue and decreases with capital costs. However, the relationship is neither:

- derived from clearly set out economic principles; nor
- estimated by reference to observed outcomes.

Once battery revenues exceed battery costs, this investment function determines the path of forward battery investment. This means that the level of battery investment estimated by the EA is not determined by reference to a model of optimal decision-making in response to economic inputs, but rather reflects a pre-determined mode of behaviour set in motion by the EA's assumptions.

[131] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 29, p 60.

Ultimately, the upper limit on aggregate battery investment determines the total battery investment in the status quo, and the assumed investment elasticity (η_b) determines how quickly that maximum is reached.

This lack of economic principle behind the EA's modelling explains the reason that it has imposed an upper limit on aggregate battery investment, which binds from 2042, as can be seen in figure 3.6 above. This would not be necessary if its investment function reflected optimal economic decision making.

We also observe that the EA models the effect of battery investment as shifting demand into the shoulder period. This produces the nonsensical result that, by the end of the modelling period, the average demand in the shoulder under the status quo is greater than average demand in the peak, indicating that at least some of the periods over which the RCPD charge is collected are likely to be in the shoulder. Figure 3.7 above demonstrates that average demand in the peak falls below average demand in the shoulder, under the status quo.

5.1.2 Benefits reflect reduced profitability of the generation sector in the wholesale market

The EA's modelling of demand response and battery investment gives rise to materially higher estimates of demand in peak periods under its proposal than with the existing RCPD charge in place. In principle, this would be expected to give rise to additional investment in generation.

However, the EA's approach to capturing investment in new generation overstates substantially the benefits of its proposal because:

- its approach to modelling generation entry is deeply flawed, resulting in the entry of significant capacity of low marginal cost generation capacity;
- its price formation mechanism is excessively simplified, forcing the EA to make a number of manual adjustments to its outputs to maintain prices in line with historical outcomes; and
- these flaws result in generators as a group earning less revenue under the proposal, despite the EA modelling substantial investment in new generation capacity.

EA's modelling of generation entry is deeply flawed

The EA states that the generation investment model selects the generation with the highest expected return from a schedule if in the given year:[132]

- the expected revenue of the generator is greater than the LRMC, inclusive of transmission costs, of the investment in that year; and
- the number of investments in the given year do not exceed a specified cap of two.[133]

In its cost benefit analysis technical paper, the EA states that revenue is calculated as the total expected revenue at a given node across the three periods and LRMC (C_{it}) is the sum of the candidate investment's LRMC and interconnection charges at the node.[134]

This approach is not reflected in its modelling. The EA's computer code instead selects the generator with the largest difference between revenue *per expected megawatt* and LRMC, inclusive of transmission costs.[135]

[132] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 25, p 54.

[133] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, para 2.225, p 54.

[134] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 54.

[135] Electricity Authority, *Grid use model*, Grid use model\Models\AoB_All_Major_Capex.py, lines 501-505.

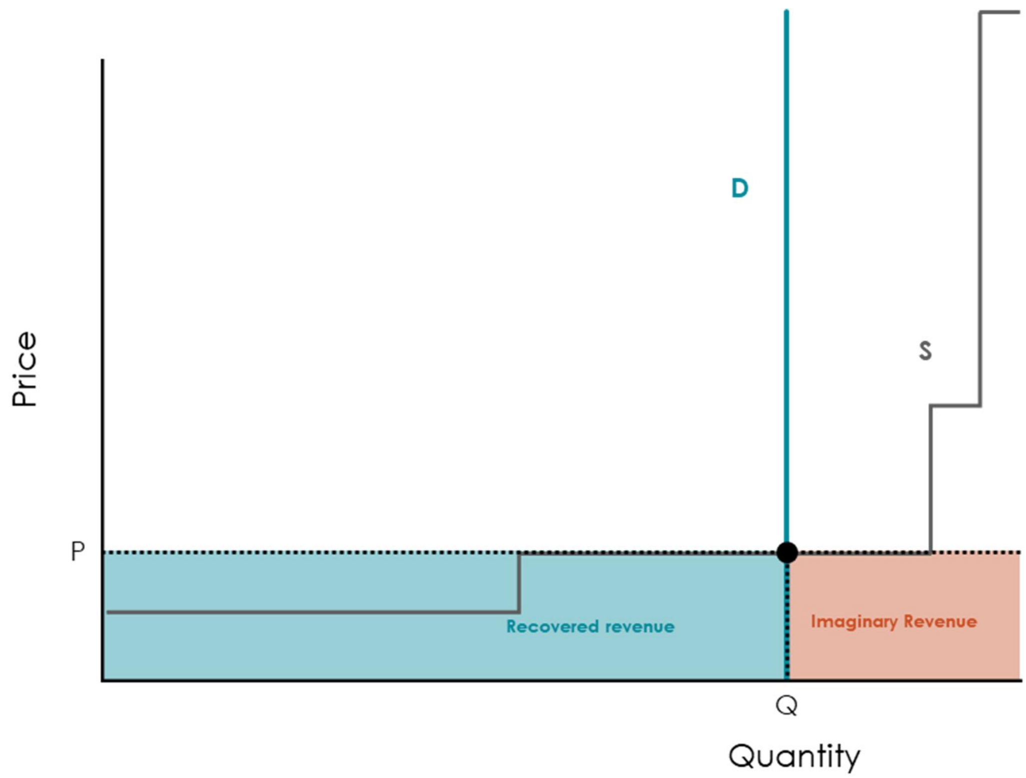
The EA's approach to modelling entry of generation is deeply flawed because it:

- assumes that each generator will dispatch every MW it offers, regardless of current or future demand; and
- only requires a generator to be profitable based on the wholesale prices in the year that it is built, assuming that it dispatches its full offers across the peak, shoulder and off-peak periods.

By assuming that each new generator dispatches its full offering in the wholesale market for its entry criteria, regardless of whether this output is required to meet demand, the EA's model relies on revenue to trigger generator entry that will not be achieved – 'imaginary revenue'. Figure 5.2 below shows the EA's estimate of revenue calculated as the price multiplied by the output offered by undispatched generators. In the figure:

- the blue shaded region represents the revenue earned by generators given demand; and
- the orange shaded region represents the further revenue that generators earn if they could sell all their quantity at the market price – the imaginary revenue.

Figure 5.2: EA's generation entry criterion relies on imaginary revenues



Source: HoustonKemp

The effect of this reliance on imaginary revenue in the EA's entry criterion is that prices can be sustained at an artificially low level and new generators can enter the market despite low prices.

EA's modelling of price formation is deeply flawed

Due to the errors that we describe above, the EA's approach to estimating wholesale prices has the potential to give rise to some extreme results, including prices near zero. However, the errors in the EA's modelling approach are obscured by the implementation of constraints on the prices emerging from its modelling, ensuring that they reflect past prices.

Table 5.1 sets out the floors and ceilings for wholesale prices that the EA employs in its grid use model, and the period of past prices that each restriction reflects.[136]

Table 5.1: Wholesale price floors and ceilings that the EA employs in its grid use model

Period	Maximum (based on year)	Minimum (based on year)
Peak	$246 per MWh (2008)	$79 per MWh (2015)
Shoulder	$178 per MWh (2008)	$79 per MWh (2009)
Off-peak	$139 per MWh (2008)	$40 per MWh (2009)

Source: Electricity Authority

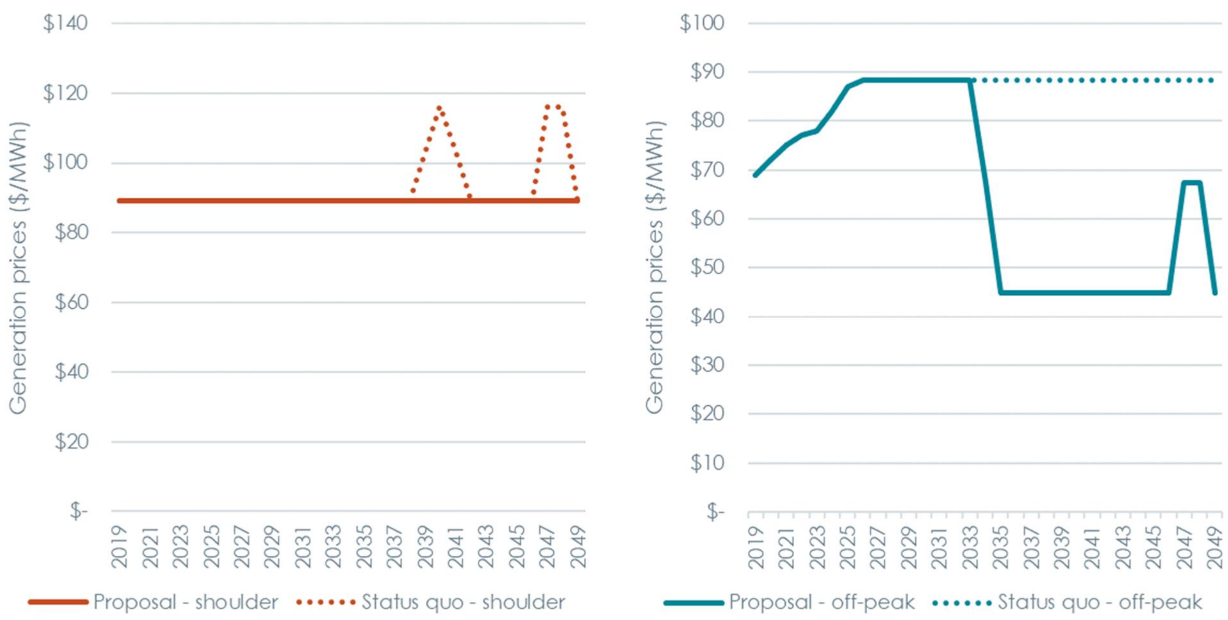
The effect of these restrictions is that off-peak prices are set almost exclusively by their upper and lower bounds of $79 and $40 per megawatt hour from 2026 onwards. This is because:

- expensive thermal generators are the marginal source of supply in off-peak periods under the status quo, and from 2026 to 2036 under the proposal, causing the price ceiling to apply; and
- hydro generators (which the EA has assumed have a marginal cost of zero) are the marginal source of supply from 2036 to 2046 under the proposal, causing the price floor to apply.

Similarly, the shoulder wholesale price floor of $79 per megawatt hour binds the entire period for the proposal, and for all except three years under the status quo.

These effects can be seen in figure 5.3 below.

Figure 5.3: Shoulder and off-peak wholesale prices, 2019 to 2049



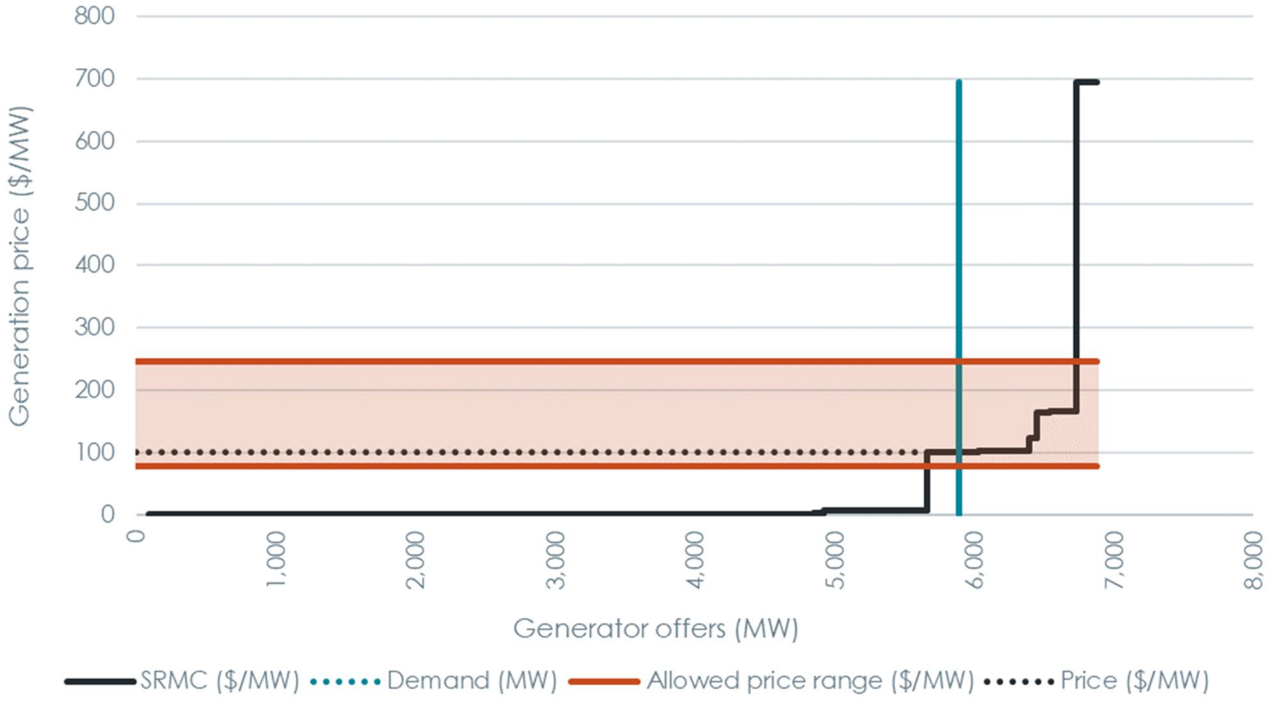
Source: Electricity Authority

[136] Electricity Authority, *Grid use model*, Grid use model\Models\AoB_All_Major_Capex.py, lines 454-468.

The EA estimates wholesale market prices as the intersection of demand with the supply curve, constructed based on the SRMC of generators in the market – also known as the 'merit order'.

For the merit order under the status quo in 2035, the marginal generator has an SRMC of $101.57 per megawatt. As this is between the upper and lower bounds of $246 and $79 per megawatt, the wholesale price is set to $101.57 per megawatt. This can be seen in figure 5.4 below.

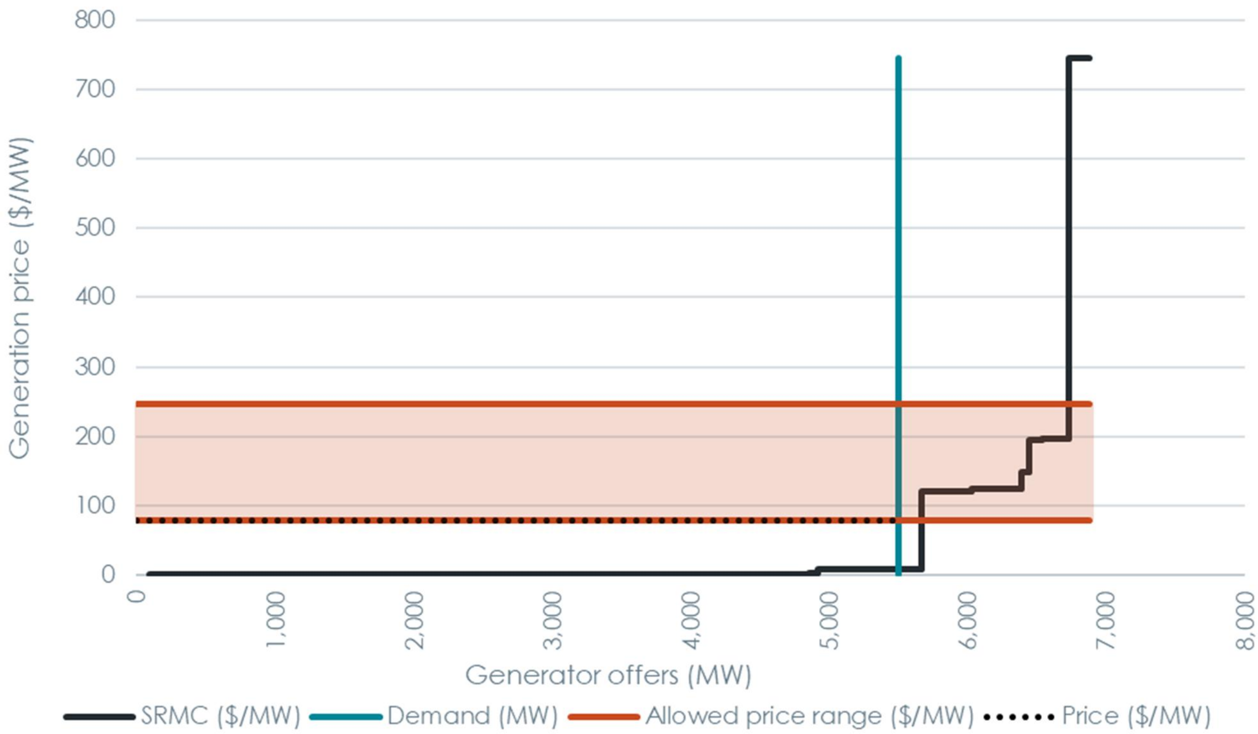
Figure 5.4: Generation merit order under the status quo in 2035



Source: Electricity Authority

Similarly, under the status quo in 2045, the marginal generator has an SRMC of $8.41 per megawatt. As this is below the lower bound of $79 per megawatt, the wholesale price is set to the lower bound $79 per megawatt. This can be seen in figure 5.5 below.

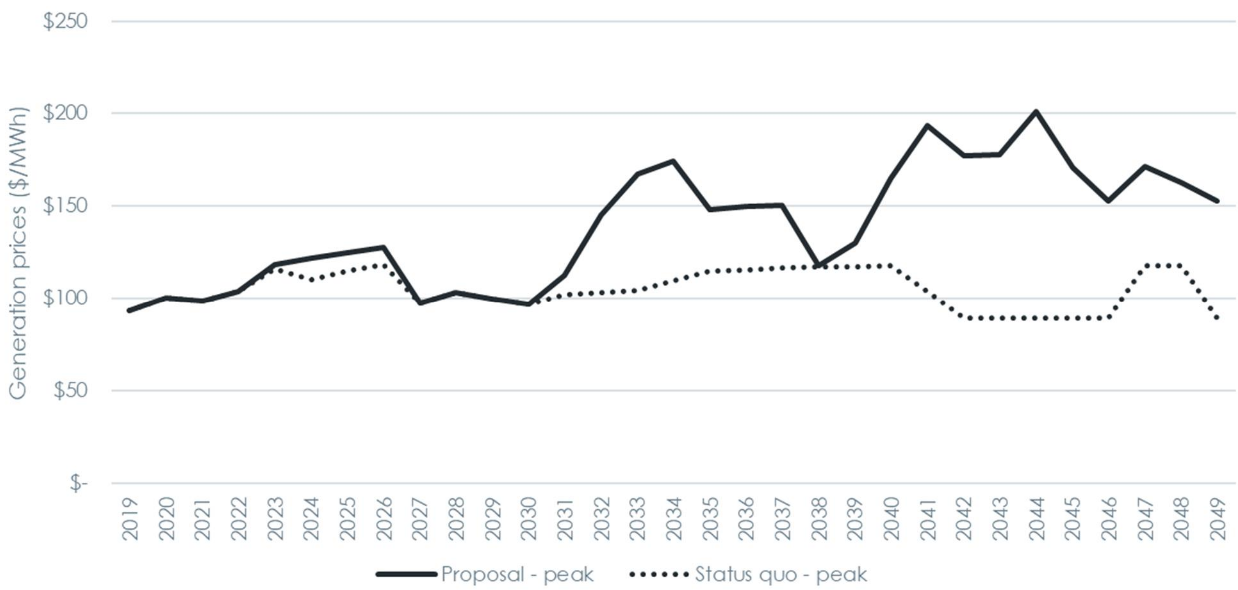
Figure 5.5: Generation merit order under the status quo in 2045



Source: Electricity Authority

The effect of these constraints can be seen in figure 5.6 below. The figure shows that the wholesale price under the status quo is constrained by the wholesale price floor from 2042 to 2046 and again in 2049.

Figure 5.6: Peak wholesale prices, 2019 to 2049



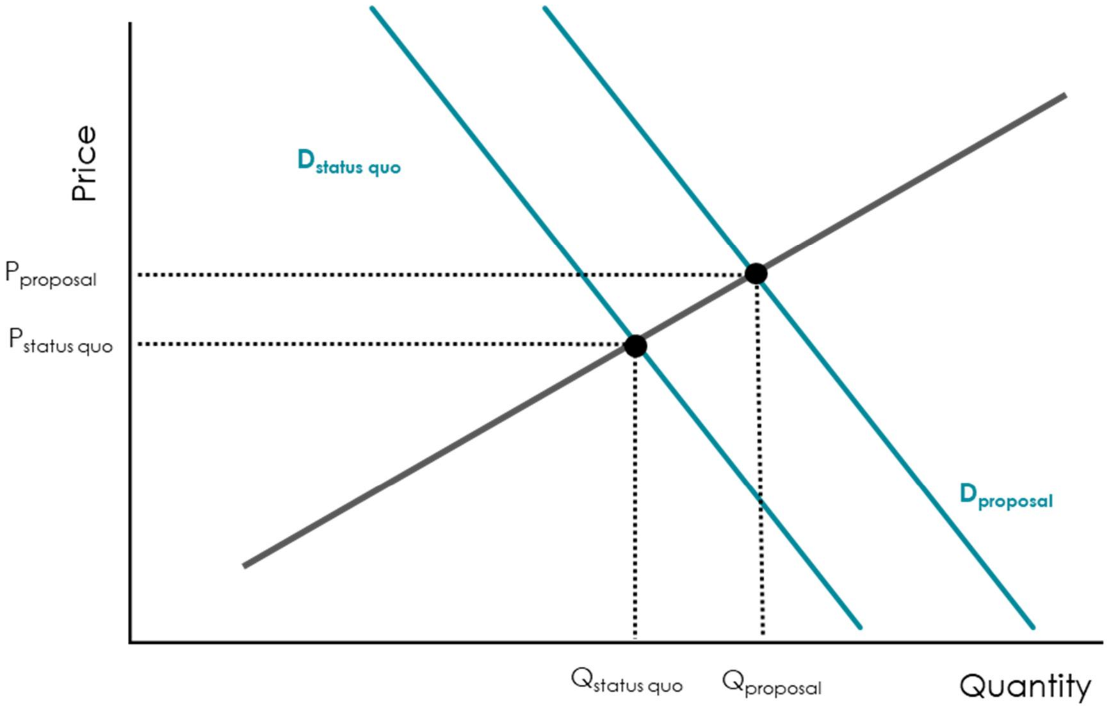
Source: Electricity Authority

EA's modelling of price formation and generator entry produce erroneous results

The result of the errors in the EA's generator entry and price formation modelling is that the increased demand predicted by the EA leads to *lower* average wholesale prices, when in fact, more generation investment typically requires *higher* prices.

We consider that a more appropriate approach would likely reflect the concept of an upward sloping supply curve. That is, as demand for generation capacity shifts out, progressively higher cost sources of supply are required in order to meet this demand.

Figure 5.7: Increasing average price under an upward sloping supply curve



Source: HoustonKemp

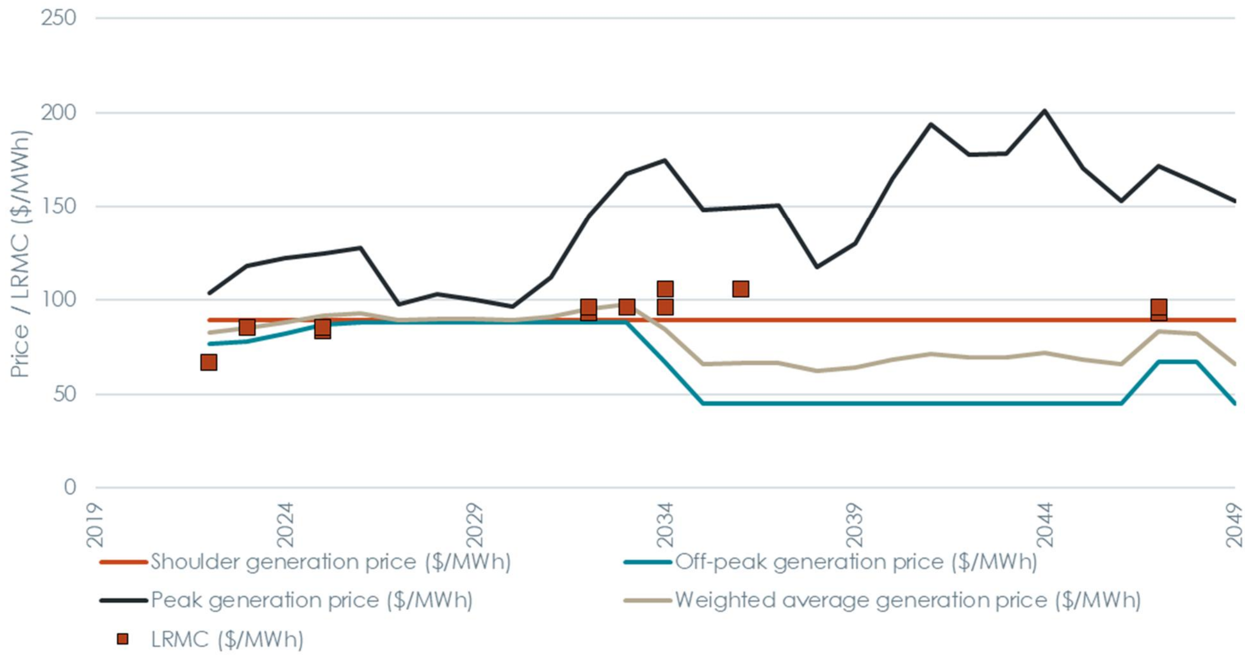
This economic logic is not consistent with the results of the EA's modelling. Although the EA assumes that progressively more expensive generators are required to enter the market to serve peak demand under its proposal, the result of these errors is that the increased demand predicted by the EA leads to *lower* average wholesale prices, when in fact, more generation investment typically requires *higher* prices.

Errors in the EA's price formation and generator entry modelling result in significant reductions in the profitability of the generation sector, arising from substantial new investment pushing down wholesale prices leading to reduced generator revenues.

Under the EA's entry criterion, generators need only be profitable in the year of entry, and their effect on prices is lagged by one year. This means that the entry of a generator has the potential to push wholesale prices below the point where that same generator becomes unprofitable the following year. In the EA's model, these generators remain in the market, operating at a loss.

This illogical result can be seen in figure 5.8 below where new entrant generator LRMCs (without transport costs) remain significantly above weighted average prices from 2034, regardless of whether their entry was dependant on the imaginary revenues that we discuss above.

Figure 5.8: New entrant LRMCs vs weighted average prices under the proposal



Source: Electricity Authority

To highlight the magnitude of the generation revenue shortfall under the proposal, under the EA's central 'all major capex' scenario, the present value of capital expenditure over the period from 2022 to 2049 amounts to:

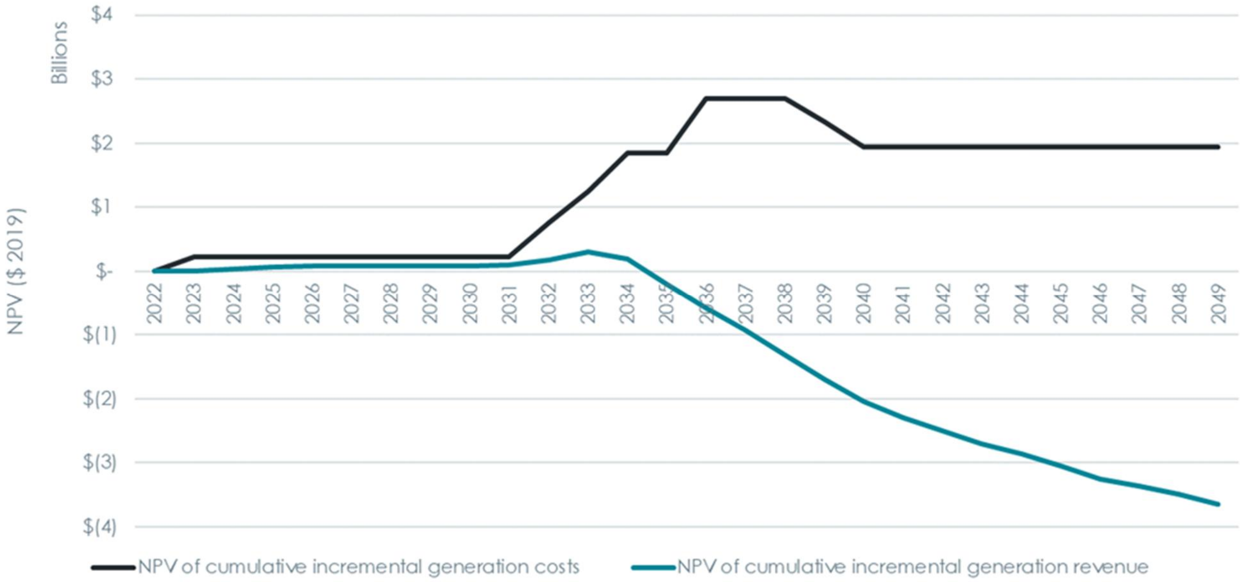
- $2,142 million under the status quo; and
- $4,082 million under the EA's proposal.

At the same time, the present value of generation revenue over the period from 2022 to 2049 amounts to:

- $44,611 million under the status quo; and
- $40,956 million under the EA's proposal.

This suggests that the effect of the EA's proposal is to give rise to an additional $1,940 million of generation investment, while reducing total generation revenues by $3,655 million. This means that over the modelling period, generators make $5,595 million less profit under the proposal. This can be seen in figure 5.9 below, which shows the incremental costs and revenues as a result of the EA's proposal.

Figure 5.9: Present value of incremental generation revenues and costs under the proposal



Source: Electricity Authority

5.1.3 Consumer surplus framework cannot reliably be applied

The consumer surplus framework that the EA applies assumes that its proposal results in a shift along the demand curve. However, when it models the changes in prices that occur under its proposal, these drive both shifts *along* the demand curve and shifts *of* the demand curve. This error of assumption means that the EA does not actually calculate the change in consumer surplus – and its estimate of benefits has no meaningful economic interpretation.

The demand curve of a good or service is the graphical representation of the relationship between its price and quantity demanded.[137] The demand curve models the relationship between price and quantity *ceteris paribus*, ie, holding all other factors constant, such as income, tastes, expectations and prices of related goods. The demand curve shifts whenever a determinant of demand other than price changes.

Under the assumption that the demand curve is straight, change in consumer surplus from a move along the demand curve can be computed from the price and quantity arising under each scenario. However, in circumstances where a shift of the demand curve has occurred, the calculation of change is no longer straightforward and requires the calculation of consumer surplus under each scenario. This involves additional assumptions about the demand curve. We illustrate, by way of example, how consumer surplus should be calculated when the demand curve has shifted in figure 5.10.

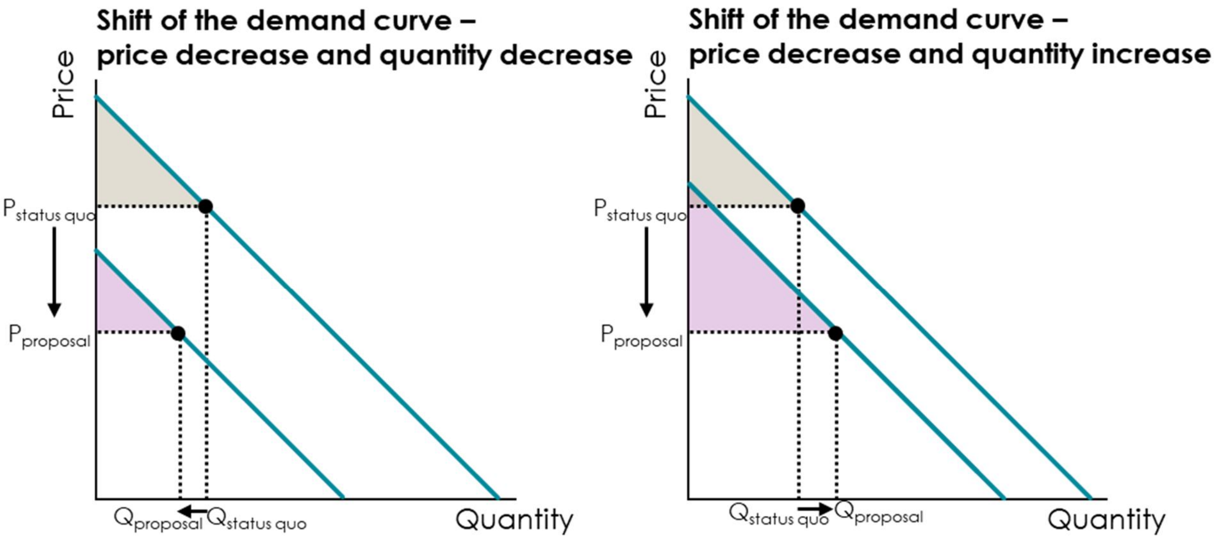
Figure 5.10 shows the change in consumer surplus as the difference between:

- consumer surplus under the proposal (shaded in purple); and
- consumer surplus under the status quo (shaded in beige).

Estimating the change in consumer surplus with a shift in demand requires knowledge of the entire demand curve – not just the slope of the demand curve around current prices and quantities.

[137] Gans, J, King, S and Mankiw, N G, *Principles of microeconomics*, Thomson Learning, Second edition, 2002, pp 66-70.

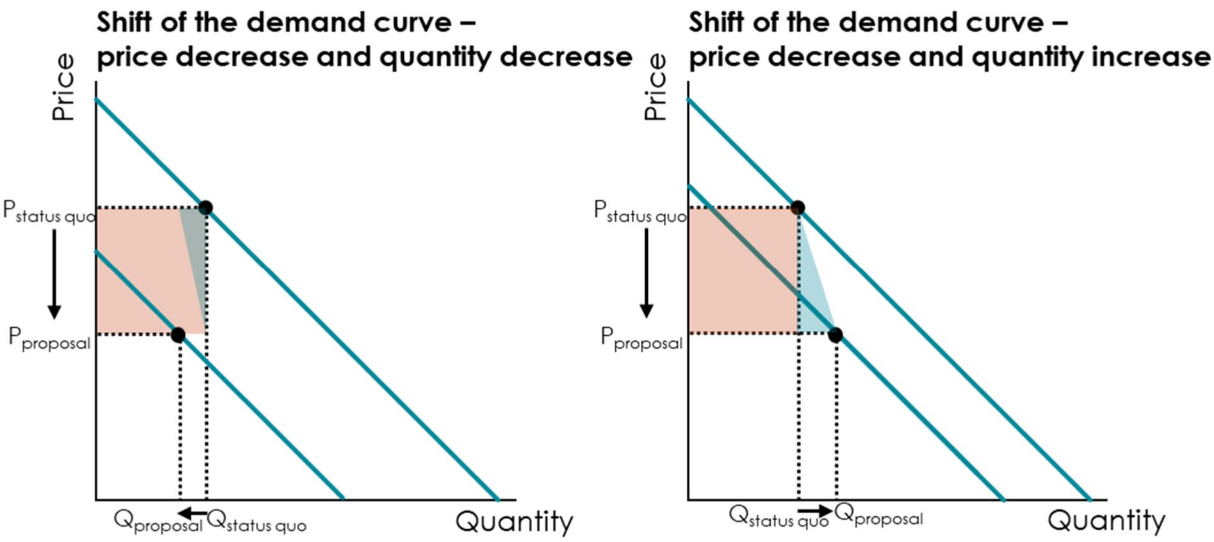
Figure 5.10: Estimating the change in consumer surplus for a shift of the demand curve



Source: HoustonKemp

By way of contrast with the change in consumer surplus shown at figure 5.10 above, figure 5.11 below illustrates the EA's calculation of the change in consumer surplus when applied in the circumstances of shifting demand.

Figure 5.11: EA's calculation does not estimate the change in consumer surplus



Source: HoustonKemp

Although its approach to calculating the change in consumer surplus assumes a shift *along* the demand curve, the EA's modelling of demand response to its proposal gives rise to shift *of* the demand curve.

These shifts occur because consumption of electricity at different times (peak, shoulder and off-peak) are related to each other, through cross-price elasticities estimated by the EA.[138] Therefore, a change in the price of electricity in one time of use period would shift the demand curve for other time of use periods. Further, the EA notes that it 'model[s] consumers switching their electricity use between different time periods (such as peak and off-peak) as prices change' in its grid use model.[139]

The outputs of the EA's grid use model provide further evidence that the EA's model reflect shifts of the demand curve. The outputs of the grid use model which form the bases of its consumer surplus estimates contain myriad examples of increases (or decreases) of both price and quantity – as shown on the left hand side of figure 5.11 above. These are inconsistent with a move along a downward sloping demand curve.[140]

5.1.4 Benefits use the results of unreliable estimation of demand elasticities

The demand elasticities that the EA uses to estimate the net benefits of its proposal are likely to determine whether these net benefit benefits are positive or negative.

This is because the TPM, as modelled in the EA's grid use model, seeks to recover sunk costs through charges on different services – being peak, shoulder and off-peak use of the grid. In economic principle, the allocation of interconnection costs to these services that maximises social welfare (or minimises deadweight loss) is an allocation that provides a mark-up for prices over marginal cost in inverse proportion to the own-price elasticity of demand.[141] This approach is commonly referred to as Ramsey pricing.

It follows that social benefits can, in principle, be maximised by:

- setting high mark-ups over marginal cost on services with relatively inelastic (or unresponsive) demand; and
- setting low mark-ups over marginal cost on services to relatively elastic (or responsive) demand.

If the price of a particular good is affected by the price of another good (ie, they are a substitutes or complements), the mark-up over marginal cost should be calculated by reference to both own-price and cross-price elasticities.[142] In general, this results in lower mark-ups for complements and higher mark-ups for substitutes.

These principles suggest that the elasticities that the EA uses will likely be very important in determining the level of net benefits that it estimates in its grid use modelling. The EA conducts its own modelling of the elasticity of demand for electricity, instead of relying upon elasticity estimates from peer-reviewed journal articles.[143]

We have several concerns about the robustness of the analysis that the EA undertakes to estimate these elasticities. In our view, these elasticities should not be relied upon and estimates from the economic literature should be preferred. We set out the reasons for these concerns below.

[138] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.69, p 33.

[139] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.66, p 33.

[140] An increase in both the price and quantity of a good is also a feature of a 'Giffen good' ie, a good for which an increase in the price raises the quantity demanded. Giffen goods have an upwards sloping demand curve. The existence of Giffen goods is a point of contention among economists and, if they do exist, they are very rare. We do not consider the possibility that electricity is a Giffen good further. Gans, J, King, S and Mankiw, N G, *Principles of microeconomics*, Thomson Learning, Second edition, 2002, p 476.

[141] Brown, S J and Sibley, D S, *The Theory of Public Utility Pricing*, Cambridge University Press, 1986, pp 39 – 43.

[142] Decker, C, *Modern economic regulation: A introduction to theory and practice*, Cambridge University Press, 2015, p 82.

[143] For example, Frontier summarise literature on empirical estimates of demand elasticities in report for Transpower, see: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower_The_Role_of_Peak_Pricing_for_Transmission_2Nov2018.pdf#page=34

Elasticity for industrial demand

The EA estimates an own price elasticity of demand for industrial customers by reference to the coefficient it estimates in its translog function on the price of electricity. It estimates that the relationship between the cost share of electricity and the price of electricity is negative, with a coefficient of -0.01 and a standard error of 0.0233.

This estimate is not statistically different from zero, indicating that the EA's econometric work cannot identify any clear relationship between the cost share of electricity and the price of electricity. Despite this, the EA uses this value to compute the own-price elasticities for a range of industries, and subsequently uses these elasticities to estimate the demand response of customers to changes in transmission charges.

Elasticity for mass market customers

The EA estimates elasticity of demand for mass market customers by reference to changes in wholesale prices. However, the vast majority of mass market customers are not exposed to changes in wholesale prices. Electricity retailers typically manage wholesale price fluctuations on behalf of customers by entering into contracts with generators.

In light of these facts, economic principles suggest that a more appropriate model of elasticity demand for mass market customers would consider changes in retail prices. The EA estimates this as an alternative specification of its dynamic panel model, the results of which it publishes in its technical paper.[144] This regression gives rise of a short run price elasticity of demand for electricity of 0.38, which is associated with a p-value of 0.20.

The direction of this elasticity is positive, which is outside the bounds of what is reasonable for an elasticity of demand estimate. Further, the p-value indicates the result is not significant at any conventional level. The long run price elasticity of demand arising from this specification of zero is similarly nonsensical.

These results suggest that either the EA is not taking into account a relevant variable, or that its data or modelling are not reliable. The EA's approach of relying instead on an elasticity measured against wholesale prices:

- is not appropriate because retail prices, rather than wholesale prices, determine the responses of mass market customers; and
- does not mitigate the concerns about its data and methods that are raised by its other results.

5.1.5 The EA's estimates of net benefits have fundamentally changed since 2016

The lack of reliability underpinning the EA's assessment of the costs and benefits of its proposal can also be shown by reference to the degree of change in its own estimates of these benefits since its previous assessment, in 2016.

In support of that proposal, the EA's consultant Oakley Greenwood estimated net benefits of $213.3 million, of which it considered that $0.3 million relates to 'more efficient quantities of services being demanded'.[145] On the other hand, for this proposal the EA estimates net benefits of $2,711 million, of which $2,579 million are associated with greater use of the grid.

The EA acknowledges this difference and states that:[146]

> These net benefits are far greater than those identified in the CBA of the 2016 TPM proposal. A key reason for this difference is that the 2016 CBA did not investigate consumer benefits arising

[144] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, Table 10, p 40.

[145] Oakley Greenwood, *Cost benefit analysis of transmission pricing options*, 11 May 2016, p 62.

[146] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, paras 4.8-4.9.

> from more efficient grid use. This was because they were considered to be minor. Instead, it focussed on the benefits from more efficient investment.
>
> Consumer benefits from more efficient grid use are an important focus for analysis in 2019. This is because the growth in transmission alternatives, and because the Authority expects consumers in the mass-market to become increasingly exposed to cost-reflective distribution pricing and real-time wholesale prices over time.

It is not accurate to state that the 2016 cost benefit analysis did not examine consumer benefits arising from more efficient grid use. These benefits were examined, and Oakley Greenwood concluded that the area of benefit charge would *increase* prices, leading to *reduced* consumption and *reduced* costs, giving rise to a small net benefit of $0.3 million. Oakley Greenwood noted that any change in consumer or producer surplus would be immaterial.[147]

On the other hand, the EA now reaches a very different conclusion. It assumes that the substantially similar benefit-based charge it now proposes would *reduce* prices, leading to *increased* consumption, but that the increase in consumer surplus that follows would be substantial, overwhelming any increase in costs.

As we set out in section 4 above, much of these conclusions turn on errors that the EA makes in the assumptions and calculation of the costs and benefits of its proposal. However, some of these can also be attributed to assumptions that the EA makes about:

- the transfer through to consumers of transmission price structures; and
- the installation of battery capacity under the status quo to take advantage of arbitrage opportunities offered by the RCPD charge.

It seems possible that the cost benefit analysis engages in this speculation about the likelihood of benefits under its proposal because there is no empirical data to draw upon that would assist with establishing the benefits to which a benefit-based charge might give rise.

In the past, the EA has cited United States RTOs as providing examples in which a benefit-based charge has been applied.[148] However, we explain in box 5.1 below that, in the United States, benefit-based cost allocation is not used to estimate charges for individual transmission users. The EA's proposal to apply benefit-based cost allocation in this way does not draw from any relevant experience in the United States and cannot be supported by reference to experience in those jurisdictions.

Box 5.1: Benefit-based allocation of transmission costs in the United States

Federal mandate requires transmission costs be allocated in a manner "roughly commensurate with benefits" wherever those costs are incurred in a manner affecting interstate commerce through the federal energy regulatory commission's (FERC) Order 1000.[149]

Applying to interstate commerce this order captures the regional transmission organizations (RTOs) which span across multiple states, including the three visited by the EA, each of which applies a beneficiaries pay cost allocation approach for at least one category of investment, ie:[150]

- midcontinent independent system operator, Inc. (MISO);
- New York independent system operator (NYISO); and

[147] Oakley Greenwood, *Cost benefit analysis of transmission pricing options*, 11 May 2016, p 52.

[148] Electricity Authority, *Transmission pricing methodology: issues and proposal: consultation paper*, 10 October 2012, para 5.6.3.

[149] Federal Energy Regulatory Commission, *Transmission Planning and Cost Allocation by Transmission*, Order No. 1000-A, 2012.

[150] Electricity Authority, Commerce Commission and Transpower, *Beneficiaries-pay in USA: Discussions on implementation of beneficiaries-pay cost allocation for transmission investment*, June 2018, p ii.

- PJM interconnection (PJM).

However not all RTOs are interstate, a notable exception is the Electric Reliability Council of Texas (ERCOT), which operates entirely within the Texas interconnection and as such is not covered by FERC's Order 1000.[151] ERCOT does not use a benefits based cost allocation method for any category of cost allocation.

Although they are covered by FERC's Order 1000, and therefore are required to allocate costs in a manner "roughly commensurate with benefits", none of the RTOs visited by the EA, or any RTO that we are aware of:

- allocates all the costs of all of their investments above some threshold in the manner proposed by the EA; or
- allocates their costs to beneficiaries at anywhere near as granular a level as proposed the EA.

1. Typically, RTOs only allocate the costs of **economic** network investments, being those designed to relieve network congestion, on the basis of benefits, and often only allocate some fraction of the benefits, as is the case with MISO, which socialises 20 per cent of the costs of economic investments.[152]
2. Upgrades triggered by a mandated **reliability** standard on the other hand are not allocated on a benefit-based approach, as these will often fail to meet the 1.25 benefit to cost ratio specified in FERC's Order 1000 and used by most RTOs, including PJM and MISO.[153]
3. The costs of projects triggered by **public policy** are often allocated on a basis specified by the policymaker, or default to a postage stamp or benefit-based cost allocation.[154]

RTOs typically rely on **pricing zones** to geographically demarcate the areas for assessment of costs and benefits on a benefit-based approach. These pricing zones correlate with large geographic or political entities, such as states, islands or large cities (such as New York city), or with the transmission owning utility companies within the RTO. Each zone is typically larger than New Zealand in geographic area, population or both.[155]

Once costs are allocated to a zone using a benefit-based methodology, costs are allocated to load serving entities (LSEs), such as distribution companies or large industrial users within the zone on a postage stamp basis, as is the case for PJM and NYISO.[156]

5.2 Improved investment efficiencies

The EA estimates total benefits of $145 million associated with improved investment efficiencies that it considers would be promoted under its proposal. All of these purported benefits are associated with the

[151] Office of Electricity Delivery and Energy Reliability, *United States Electricity Industry Primer*, United States Department of Energy, 2015.

[152] Electricity Authority, Commerce Commission and Transpower, *Beneficiaries-pay in USA: Discussions on implementation of beneficiaries-pay cost allocation for transmission investment*, June 2018, p 14.

[153] Federal Energy Regulatory Commission, *Transmission Planning and Cost Allocation by Transmission*, Order No. 1000-A, 2012; Electricity Authority, Commerce Commission and Transpower, *Beneficiaries-pay in USA: Discussions on implementation of beneficiaries-pay cost allocation for transmission investment*, June 2018, pp 14, 17.

[154] Electricity Authority, Commerce Commission and Transpower, *Beneficiaries-pay in USA: Discussions on implementation of beneficiaries-pay cost allocation for transmission investment*, June 2018, pp iii, 8.

[155] Electricity Authority, Commerce Commission and Transpower, *Beneficiaries-pay in USA: Discussions on implementation of beneficiaries-pay cost allocation for transmission investment*, June 2018, p iii.

[156] New York Independent System Operator, Inc., *NYISO OATT*, 2019, pp 21-35, Appendix Y; Electricity Authority, Commerce Commission and Transpower, *Beneficiaries-pay in USA: Discussions on implementation of beneficiaries-pay cost allocation for transmission investment*, June 2018, p 16.

introduction of the benefit-based charge – unlike the benefits associated with the grid use modelling, which predominantly relate to increased utilisation of the transmission network.

In our view:

- the modelling of investment efficiencies assumes that the benefit-based charge sends a cost-based pricing signal, which is not a component of the EA's proposal; and
- the calculation of benefits associated with increased scrutiny and increased durability of the proposal are entirely unreliable since the depend on assumptions which cannot be confirmed by reference to facts.

5.2.1 More efficient decisions by large loads defer transmission investment

The EA estimates benefits of $31 million associated with more efficient decisions by large loads that have the effect of deferring transmission investment. We describe the framework and assumptions that underpin this estimate in section 3.2.1 above.

The key assumption that underpins the EA's estimate of benefits is that its benefit-based charge sends a cost-based price signal that gives rise to desirable behavioural responses by users. We set out in section 7 below that this assumption is not well justified and cannot be assumed – it must be shown.

Setting aside this concern, we consider that the modelling framework that EA applies to estimate this benefit is broadly reasonable. However, the inputs that it uses are open to question. There are also likely to be several additional benefits associated with reductions in peak demand that the EA does not capture within its framework but should do so, consistent with our observations in section 4 above.

For these reasons we consider that the EA's estimate of benefits in this category overstates the impact of the benefit-based charge on peak demand and therefore on transmission costs. However, if there is any reduction in peak demand then, consistent with our views in section 4 above, the EA should also take into account the savings associated with lower generation and distribution investment.

The remainder of this section sets out our views on these matters in greater detail.

EA's modelling framework is sensitive to key assumptions

The modelling framework reflects the way in which the EA anticipates that a benefit-based charge would manifest – in more concentrated price signals to transmission users.

However, we note that benefits estimated under the framework are sensitive to key assumptions, in particular:

- the assumption that the average quantity of demand from which a benefit-based charge is expected to be recovered is 2,464 MW; and
- the assumption that the long run elasticity of demand is -0.74.

The EA states that it estimates 2,464 MW as the average of peak grid demand across regions that would be beneficiaries of Transpower's enhancement and development capital expenditure program. This amounts to 33 per cent of network peak demand in 2022. However, the EA does not state which regions would benefit from these programs or how it has made this determination.[157]

We consider that this value is likely to be subject to considerable uncertainty. By way of example, the EA's Monte Carlo analysis provides for the share of demand to which benefit-based charges apply to vary between 0 per cent and 100 per cent.

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[157] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, p 81.

We observe the results of the EA's analysis are sensitive to this assumption. For example:

- if the relevant demand were half the level estimated by the EA, its benefits would be 144 per cent higher; whereas
- if the relevant demand were twice the level estimate by the EA, its benefits would be 72 per cent lower.

The benefits are also sensitive to the assumed level of price elasticity for electricity. The EA assumes a long run estimate of price elasticity of -0.74. However, if it had used a value for elasticity consistent with the assumptions in its grid use model (-0.11 for households and -0.02 for industrial customers) then its benefits would have been proportionately lower – approximately between $1 million and $5 million.

Benefits should also include generation and distribution costs savings

In sections 4.2 and 4.3, we explain that in estimating the costs and benefits associated with greater grid use, the EA should account for changes in generation and distribution costs that are associated with increases in peak demand under it proposal.

If a response to benefit-based charges gives rise to a reduction in peak consumption, then consistent with these views, the EA should consider the extent to which this response would offset some of the costs associated with increased grid use. Consideration of these avoided costs would increase the EA's estimates of benefits.

However, we note that these benefits are not likely to exceed in magnitude the costs that we estimate in section 4 above, because the reduction in peak demand that the EA estimates in connection with the application of a benefit-based charge is much lower in magnitude than the increase in peak demand that the EA calculates from the removal of the RCPD charge.

5.2.2 More efficient decisions by generators defer transmission investment

The EA estimates a further $11 million of benefits associated with more efficient decisions by generators which lead to the deferment of transmission investment under its proposal. We describe the framework and assumptions that underpin this estimate in section 3.2.2 above.

In our view, the modelling framework used by the EA does not give rise to an estimate of the benefit that it seeks to measure. This is because the EA estimates the effect of a benefit-based charge by reference to an average 0.5 per cent decrease in generation capacity in constrained areas, estimated in the grid use model as between:

- the 'all major capex' scenario; and
- the alternative scenario.

We understand that the 'all major capex' scenario includes inputs that establish the share of the benefit-based charge. This scenario assumes that generators are invoiced the benefit-based charge in each year as an explicit price signal. In this respect, it assumes that the shadow price signal sent by benefit-based charges works as effectively as if it were a price signal.

The EA calculates the 0.5 per cent decrease in generation capacity in constrained areas by comparing the share of network generation in constrained nodes with the proposal as against under the status quo. This calculation does not establish that the proposal would give rise to a reduction in costs. For there to be a reduction in costs requires that generation capacity would give rise to the need for transmission investment under the status quo whereas it would not under the proposal.

To the extent that decreases in generation in constrained areas assists in relieving this pressure, it is the absolute decrease in generation capacity at each node that provides this relief. The change in the proportion of generation capacity in constrained areas does not inform this calculation – the proportion could have decreased simply because generation capacity in unconstrained areas has increased. Figure 3.19 above suggests that this has largely been the case, and that the total level of generation in constrained areas is the same under the proposal and the status quo in most years.

5.2.3 Greater scrutiny by stakeholders gives rise to more efficient grid investment

The EA estimates benefits of $77 million associated with greater scrutiny of investment proposals by stakeholders. We describe the framework and assumptions that underpin this estimate in section 3.2.3 above.

Additional scrutiny of investment proposals is said to arise due to the introduction of a benefit-based charge, and to give rise to efficiency benefits of between one and four per cent. The EA's estimate of benefits turns on these assumptions. The empirical rationale for this range of estimates is based on a reduction of 4.4 per cent that the Commerce Commission applied to Transpower's proposed enhancement and development capex in the context of RCP2.

In our view, this is an unreliable basis for estimating the potential benefits associated with additional scrutiny and likely to overstate the benefits because:

- the EA relies upon the single observation of the Commission's review – this does not provide a reliable basis to conclude that 4.4 per cent reasonably represents the expected outcome of this form of scrutiny;
- it is incorrect to describe changes to Transpower's expenditure program that follow the Commission's review wholly as benefits, since a reduction in expenditure may result in fewer services, lower reliability or increased future expenditure; and
- the basis upon which the EA considers that stakeholders would not just replicate the outcome of the Commission's review processes but improve on them is unexplained.

Consistent with these observations, our view is that any benefits associated with increased scrutiny are likely to be small, relative to the EA's estimate.

The remainder of this section sets out our views on these matters in greater detail.

EA relies on a single observation of scrutiny by the Commission

The EA draws on a single example to support its range of estimates for the efficiency savings from greater scrutiny. This does not appear to be a reliable basis upon which to base any estimate.

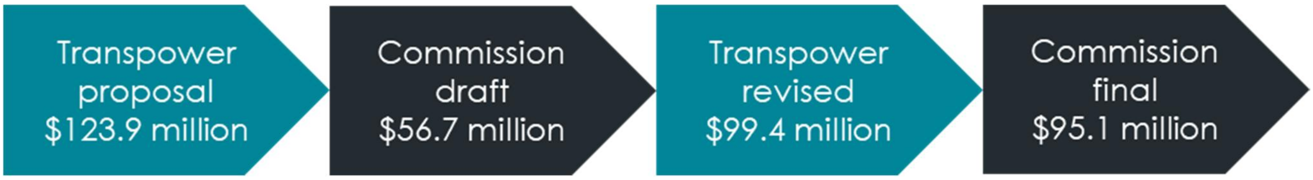
The reduction of 4.4 per cent cited by the EA relates to the Commission's final decision in RCP2 to reject Transpower's revised proposal of $99.4 million for enhancement and development capex and substitute this with its own estimate of $95.1 million.[158]

However, this was only one phase of the Commission's consideration of Transpower's capital program. Figure 5.12 below shows how Transpower's initial proposal of $123.9 million was ultimately reduced to a final allowance of $95.1 million. The EA focuses only on the final step of this consultation. However, it would be equally valid to say that:

- the Commission's review process reduced Transpower's proposed enhancement and development capex by 23.2 per cent, from $123.9 million to $95.1 million; and
- the Commission's draft decision reduced Transpower's proposed enhancement and development capex by 54.2 per cent, from $123.9 million to $56.7 million.

[158] Commerce Commission, *Setting Transpower's individual price-quality path for 2015-2020*, 29 August 2014, pp 75-76.

Figure 5.12: Commission's consultation on Transpower's enhancement and development capex



Source: Commerce Commission

There is nothing that is uniquely informative about the final step of the Commission's consultation process in establishing the benefits of scrutiny. Indeed, there are numerous other processes that the Commission and other regulators are engaged in which the EA also could have reviewed.

Expenditure reductions determined by the Commission are not wholly benefits

The EA's reliance on reductions imposed by the Commission on Transpower's capital expenditure programs assumes that these reductions are wholly benefits – that is, that customers are receiving the 'same' but for 'less'. This is not the case.

When it reviews Transpower's capital expenditure program, the Commission's approach is to allow expenditure that has been justified by reference to whether it is prudent and efficient. The Commission's advisor, Strata, recommended that the Commission not allow:[159]

- the proposed Wiri tee – Wiri capacity upgrade project because the need and cost was not explained by Transpower;
- the PD42 Islington spare transformer switchgear because it would provide reliability that exceeds the mandated standards; and
- the PD43 Haywards local service third income because it would provide reliability that exceeds the mandated standards.

It is clear from this summary that the Commission is not removing entirely wasteful expenditure from Transpower's capital expenditure program. It is removing expenditure that has not been justified or is not required to meet reliability standards. This does not mean that the expenditure gives rise to no benefits – rather, that the benefits have either not been established to the satisfaction of the Commission and its advisors, or that the benefits may be less than the costs. It follows that it is not reasonable to interpret the reductions in Transpower's capital expenditure program as being entirely a benefit to society.

In any case, a reduction in Transpower's capital expenditure program does not mean that this expenditure will not go ahead. Transpower could still proceed with that expenditure during the regulatory period (depending on the need) or it could reintroduce the proposed expenditure at the next regulatory period. However, the EA's interpretation of the result of this consultation assumes that 4.4 per cent of the expenditure program is permanently saved.

EA assumes that scrutiny by stakeholders would further that already undertaken by the Commission

If the reductions achieved by the Commission on Transpower's capital program were correctly characterised as savings due to scrutiny, the basis on which the EA considers that increased scrutiny could give rise to further savings is unclear.

[159] Strata Energy Consulting, *Review of points raised in submission on the draft decision for the Commerce Commission*, 19 August 2014, pp 14-25.

The Commission's process, described in figure 5.12 above, investigates Transpower's expenditure on a project by project basis, and identifies where this expenditure may not be prudent or efficient. This process occurs twice – once at the draft decision phase and again in the final decision. During the RCP2 process, the Commission sought expert assistance to review Transpower's expenditure proposals. Stakeholders have the ability to provide input and did so.[160]

The EA has not been able to articulate what concern it has with the Commission's existing process such it believes that is currently not effective at restraining transmission investments to a level that is efficient, or the mechanism by which the benefit-based charge will give rise to more efficient investment or to reduce inefficient investment. It has not provided any examples of withheld information under the current approval system or explained how information about alternatives to network investment would align with the processes that would be required to implement its proposed benefit-based charges.

The fact that some parties might be more highly incentivised to seek roll backs in particular investments does not suggest to us that the Commission will undertake its process any differently or come to a different decision as to what expenditure should be allowed to enter the regulatory asset base. The process of proposing and approving transmission investments is distinct from any process that will determine the allocation of costs in proportion to benefits.

This observation draws a clear distinction between the arrangements under which the EA's proposal would operate and how benefit-based charges operate in the United States, from where the EA draws its inspiration. It is notable that, in the United States, the agency that reviews and approves investments is also the agency that determines the beneficiaries and allocates costs to them. These arrangements highlight the very different circumstances under which benefit-based charges are applied in the United States, as we note in box 5.1 above.

5.2.4 More certain policy environment reduces the cost of investment

The EA estimates benefits of $26 million associated with a more uncertain policy environment under its proposal, as compared with under the status quo. We explain the assumptions and methods that underpin this estimate in section 3.2.4 above.

Contention arises in situations where there is a prospect that a reallocation of the costs of existing investments might give rise to winners and losers from a reform. This has been a prospect for over eight years under the continued transmission pricing reform program instigated by the EA. In our view, the EA's proposal does not give rise to certainty and we would not expect it to engender any benefits associated with durability. We explain the basis for this view in more detail in section 6.1.3 below.

The modelling that underpins the EA's calculation of net benefits turns on two unsupported assumptions that determine the magnitude of the benefits that it estimates. These assumptions are that:

- under the EA's proposal, there would be one event of political uncertainty every 11 years, as compared to every 10 under the status quo; and
- the level of uncertainty under the status quo is 100.

The nature of these assumptions discloses that the EA's estimate of the benefits of durability does not rest on any evidentiary basis. It is more accurately described as a contention, rather than an estimate. In our view, the EA should not pursue the calculation of a durability benefit – a benefit that in any case assumes net benefits associated with its proposal that have not been established.

[160] Strata Energy Consulting, *Review of points raised in submission on the draft decision for the Commerce Commission*, 19 August 2014, p 10.

In addition to these two unsupported assumptions, there are a number of other assumptions that are inadequately supported in the calculation of the durability benefit. We discuss our concerns about these assumptions in more detail below.

Uncertainty would not be likely to reduce under the proposal

The EA asserts that, under its proposal, there would be one event of political uncertainty every 11 years. This represents a nine per cent reduction in uncertainty from the status quo, in which there would be one event of political uncertainty every 10 years.

This assumption appears to be one of convenience, establishing a quantitative framework from which to conclude that the proposal would reduce uncertainty. However, there is no basis in fact for this assumption.

There is no evidence that political uncertainty in relation to the TPM arises every 10 years under the status quo. Uncertainty in relation to the TPM arises on each occasion that the EA seeks to review and change the basis for determining the TPM – and in particular, the allocation of the costs of existing investments. On this basis, the current frequency of these events is entirely determined by the EA.

It may well be the case that the EA considers that, were the TPM guidelines to be implemented, it would no longer need to undertake further reviews of the TPM framework and that this would alleviate the uncertainty associated with these actions. This approach, while revealing a strong level of commitment to its reform, does nothing to identify whether the EA's proposal gives rise to net benefits that would be worth sustaining into the future.

There is no basis for establishing the current level of uncertainty

We describe above that the EA assumes that its reform reduced uncertainty by nine per cent. However, the EA cannot use this assumption to estimate the expected change in quantity consumed under its proposal because it estimates the quantities demanded and supplied by reference to the absolute level of uncertainty.

The EA appears to have circumvented this problem by assuming that the initial level of uncertainty under the status quo was 100, and that this falls to 91 under its proposal. The EA describes this assumption as representing an 'index' for uncertainty – apparently on the apprehension that this might provide a rationale for setting the level at 100.[161]

However, there is no basis for setting the level of uncertainty under the status quo to 100. There is no evidence that would support or reject this claim, or render it consistent with any other assumption in its analysis. The EA could equally have claimed initial uncertainty to be any other positive number.

By way of concrete example:

- if the EA had assumed that uncertainty under the status quo was 1, it would have estimated net benefits of $0.3 million; and
- if the EA had assumed that uncertainty under the status quo was 10,000, it would have estimated net benefits of $2,622 million.

Based on the information that the EA has to hand about the current level of uncertainty, either of these estimates would have been equally plausible – and equally unreliable – as the EA's estimated net benefits.

Due to this concern, there is no basis at all for the level of net benefit that the EA estimates associated with durability. Its estimate of this benefit scales up and down with its assumed level of uncertainty under the status quo, which has no basis in either fact or principle.

[161] Electricity Authority spreadsheet, *Investment efficiencies model.xlsx*, worksheet 'Durability'.

Other errors affecting the benefits of durability

In addition to the errors that we identify above, the EA's estimate of benefits associated with durability is affected by two other errors that impact on its reliability.

Firstly, we explain at footnotes 89 and 90 above that the EA makes an algebraic error in its workings which causes it to incorrectly express its formula for the equilibrium price, and for the effect of uncertainty on price. This causes the EA to incorrectly estimate that a *decrease* in uncertainty would give rise to an *increase* in price. In fact, under its assumptions, the change in price should be zero.

The slope coefficient of price against uncertainty should correctly be expressed as:[162]

$$\left(\frac{\delta_s - \delta_d}{\beta_s - \beta_d}\right)$$

Under the EA's assumption that $\delta_d = \delta_s$, increased uncertainty has no effect on price. We consider this assumption to be much more plausible than the relationship modelled by carrying forward the EA's algebraic error.

Secondly, the EA estimates the relationship between uncertainty and investment in the electricity transmission sector in New Zealand by reference to the relationship estimated between uncertainty in economic policy and investment in the United States.

We agree in principle that there is likely to be a positive connection between certainty and investment. This is the basis for some of our concerns about the effectiveness of the EA's benefit-based charge in section 7.4 below.

However, the empirical evidence relied upon by the EA is simply too remote in nature to be reliable for the purpose of establishing a link between uncertainty surrounding TPM policy and investment in transmission investment in New Zealand. Combined with the other assumptions that underpin the calculated benefit of $26 million, this assumption underscores that there is no valid empirical basis for a durability benefit.

[162] Electricity Authority, *CBA approach, methods and assumptions | 2019 issues paper: Technical paper | Information paper*, 23 July 2019, equation 43; and Electricity Authority spreadsheet, *Investment efficiencies model.xlsx*, worksheet 'Durability'. This equation is also affected by the error noted in footnote 89 above.

6. Inconsistency with best practice approach

Sections 4 and 5 above establish that the framework that the EA uses to evaluate the costs and benefits of its proposal is not implemented correctly, and the assumptions and methods that inform this framework are not fit for purpose. As a result, the cost benefit analysis is not likely to give rise to reliable or accurate estimates of the extent to which the EA's proposal gives rise to benefits that outweigh its costs.

In this section we explain that the EA's cost benefit analysis does not follow best practice because:

- it does not explore alternative options to the EA's proposal or test the proposal against potential alternatives, such as excluding the reallocation of seven historical investments on beneficiary-pays principles; and
- it incorrectly specifies the status quo in all scenarios by inappropriately assuming that the RCPD charge would remain at the current strength and give rise to inefficient outcomes, notwithstanding Transpower's ability to change this under the current TPM guidelines.

The EA should not assume the efficiency of its proposal and should explore whether other proposals might, in practice, better address the problems with the current TPM than its preferred option. This should include options that do not reallocate the costs of historical investments. In our view, it would be more consistent with the efficient operation of the industry for an options analysis to be conducted now, rather than after Transpower has considered the EA's proposal.

6.1 Alternative options are not explored by the cost benefit analysis

Cost benefit analysis is a tool to determine how best to address a policy problem. It provides a means to explore potential options and identify which of these options, if any, best addresses the problem.

This purpose sits in contrast to the use that the EA makes of cost benefit analysis. The EA appears to be wholly persuaded of the merits of its proposal on the basis of economic principle and the purpose of cost benefit analysis in its consultation paper is limited to verifying the magnitude of the benefits that would be realised by the proposal. This frame of reference is explicitly disclosed in the first paragraph of the cost benefit analysis section in the consultation paper, where the EA states:[163]

> A cost-benefit analysis (CBA) seeks to quantify the proposal's net benefits to consumers.

In this section we explain that:

- cost benefit analysis is a framework for assessing and ranking alternative options for addressing a problem; but
- the EA's cost benefit analysis does not rigorously test its proposal against other options for addressing the problems that it identifies.

6.1.1 Cost benefit analysis is a framework for assessing options

The purpose of cost benefit analysis is to place rigour around the making of a decision to address a problem, so that the decision maker understands the impact that its decision will have both in aggregate and in terms of the distribution of effects. The New Zealand Treasury explains in in its guide to social cost benefit analysis:

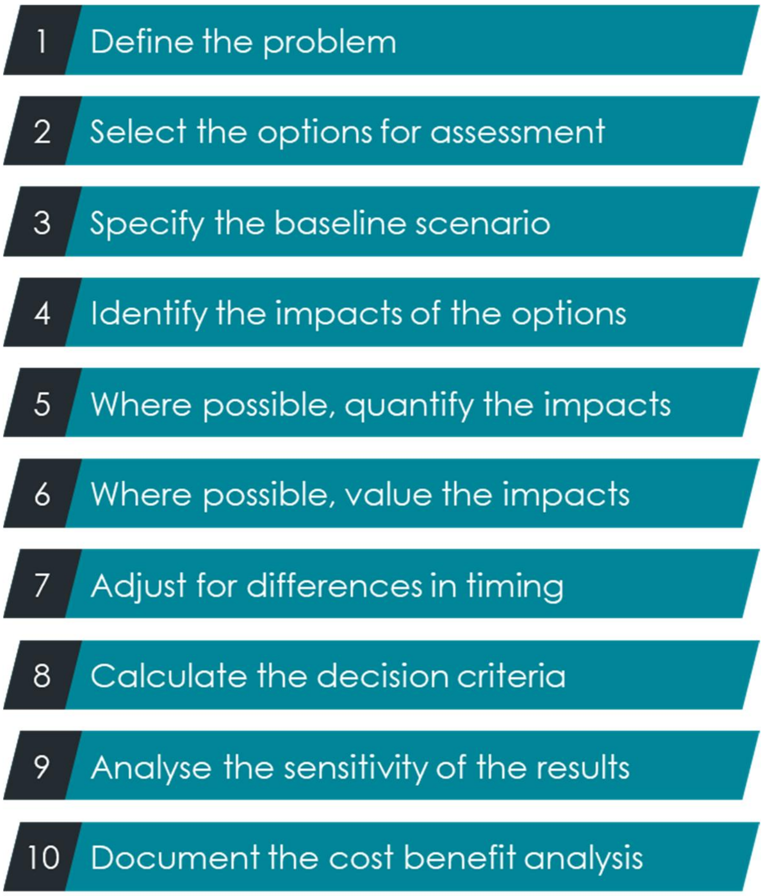
[163] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.1.

> All decisions require some kind of formal or informal CBA. The main purpose of this guide is to encourage all decisions to be accompanied by at least a rough CBA, on the grounds that it is likely to be better than decision-making based on prejudice or instinct.

Apart from identifying reform options with the greatest estimated net benefits, a robust cost benefit analysis can assist in realising the benefits of the option which is ultimately adopted. Specifically, by articulating the costs and benefits of the preferred option, stakeholders form broad expectations as to how the option is likely to perform, which in turn assists in monitoring actual costs and benefits once the option is implemented.

The EA's cost benefit analysis working paper sets out a ten step process for undertaking a cost benefit analysis. In summary, the steps it identified are set out in figure 6.1 below, which includes a selection of options for assessment and identification of the impacts of these options.

Figure 6.1: EA's ten-step process in undertaking a cost benefit analysis



We consider that this list of requirements is broadly sensible and consistent with other policymaker's prescriptions for undertaking similar analyses. For example, the New Zealand Treasury's guide to social cost benefit analysis sets out a substantially similar seven-step process.[164]

History of TPM cost benefit analysis

We understand that the EA is required to undertake a cost benefit analysis whenever it proposes a change to the Code. Section 39(2) of the *Electricity Industry Act 2010* stipulates that:

[164] New Zealand Treasury, *Guide to social cost benefit analysis*, July 2015, p 8.

> The regulatory statement required for a proposed amendment to the Code must contain the following:
>
> (a) a statement of the objectives of the proposed amendment;
>
> (b) an evaluation of the costs and benefits of the proposed amendment;
>
> (c) an evaluation of alternative means of achieving the objectives of the proposed amendment.

TPM guidelines are not technically part of the Code, but the TPM that is developed to comply with them is. The EA has taken the view that, given this process may give rise to changes in the Code, it would be helpful to develop a cost benefit analysis and an assessment of alternatives as part of the development of the TPM guidelines.[165] This approach is also consistent with the EA's obligation to follow processes that are consistent with the efficient operation of the industry.

However, it has not yet been able to produce a robust analysis in support of its proposals. In the past there has been criticism of the cost benefit analyses undertaken by or on behalf of the EA in support of proposed changes to the TPM. Specifically, concerns were raised in response to:

- the cost benefit analysis undertaken by the EA which supported the proposals in its issues paper released on 10 October 2012;[166] and
- the cost benefit analysis undertaken by Oakley Greenwood which supported the proposals in the EA's second issues paper released on 17 May 2016.[167]

The concerns that were raised were significant, with material consequences.

After the EA decided to begin work on a second issues paper, it instigated a working paper process to address and respond to concerns and suggestions raised in response to its first issues paper. The first working paper that it prepared set out a revised approach and method for a cost benefit analysis.[168]

Subsequently, the EA appointed Oakley Greenwood to prepare the cost benefit analysis that it used in support of its second issues paper.[169] However, this analysis was shown to be affected by serious errors which called into question its robustness.[170] These findings led to a further delay in the development of TPM guidelines, with the EA having only now released its next proposal more than two years after these errors were identified.

Against this backdrop of strong criticism of its previous analysis, it is important that the EA's consultation process includes a thorough and robust analysis of the costs and benefits arising from its proposal, as against other means of addressing the problems that the EA identifies.

6.1.2 The EA's cost benefit analysis does not assess its proposal against meaningful alternatives

A cost benefit analysis should assess a proposal against meaningful alternative options. This ensures that the proposal is tested against potential alternative means of meeting the same objectives.

In our opinion, the EA's cost benefit analysis does not assess its proposal against meaningful alternative options. Rather, the EA:

[165] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para E.1.

[166] Electricity Authority, *Transmission pricing methodology: issues and proposal: consultation paper*, 10 October 2012.

[167] Electricity Authority, *Transmission pricing methodology: issues and proposal: second issues paper*, 17 May 2016.

[168] Electricity Authority, *Transmission pricing methodology: CBA working paper*, 3 September 2013.

[169] Oakley Greenwood, *Cost benefit analysis of transmission pricing options*, 11 May 2016.

[170] See for example: New Zealand Herald, *Electricity Authority dumps transmission pricing modelling*, 26 April 2017.

- assesses its proposal against an option that it describes as a 'broad based usage' charge, which does not appear to be a carefully considered alternative proposal;
- discusses qualitatively for four selected alternative charges why it does not prefer each of these to its current proposal; and
- mentions other charges that it has previously considered, which it states it does not prefer to its current proposal.

It is important for the eventual success of any reform to the TPM that a robust and transparent evaluation of the costs and benefits of the reform and potential alternatives is undertaken in the proposal phase. This is of particular importance in the context of TPM reform, where two previous cost benefit analyses undertaken by or on behalf of the EA have been subjected to strong criticism.

Cost benefit analysis tests the EA's proposal against a single alternative

The cost benefit analysis prepared by the EA presents its proposal against a single alternative, which it describes as a 'broad based usage' charge.

This alternative is not extensively described or set out. In appendix E to its consultation paper, the EA describes the motivation for including this charge:[171]

> In the CBA, we have considered retaining the current pricing methodology but with RCPD required to be calculated using all trading periods so that the RCPD charge becomes a MWh charge. A charge based on load is likely to have a similar effect to a small sales tax on energy sales. It is therefore likely to substantially ameliorate the inefficiency caused by the RCPD charge. As a result, this option is likely to be more efficient than the status quo.

We note that the EA also considers or refers to alternative proposals that is does not assess using its cost benefit framework.

EA refers qualitatively to four alternatives

In appendix E to the consultation paper, the EA describes qualitatively why it prefers its proposal as compared to:

- addressing problems with the RCPD charge under the current TPM guidelines;
- using the simplified staged approach proposed by Transpower in 2016;
- applying a deeper connection charge; and
- adopting a tilted postage stamp charge.

[171] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para E.100.

Table 6.1: Reasons why the EA prefers its proposal to alternative options

Alternative options	Reason why the EA prefers its proposal to the alternative option
Current guidelines	Beneficiaries of a new investment would not face their share of the cost of the investment, so grid users would make usage and investment decisions without taking into account the impact of those decisions on grid investment.[172]
Simplified staged approach	Beneficiaries of a new investment would not face their share of the cost of the investment, so grid users would make usage and investment decisions without taking into account the impact of those decisions on grid investment.[173]
Deeper connection charge	The deeper connection charge would not promote efficient investment because it would apply only partially (or not at all) and the charge would not be aligned with benefits – some customers may be charged more than their benefits. The charge could inefficiently distort behaviour and would be complex to implement.[174]
Tilted postage stamp charge	Charges transmission users pay for a new investment would not reflect the costs of those investments, so grid users would make usage and investment decisions without taking into account the impact of those decisions on grid investment.[175]

Source: Electricity Authority

The rationales disclosed by the EA for rejecting these alternatives are based entirely on economic principle – the EA believes that its reform would ensure that beneficiaries bear their share of the cost of a new investment, whereas the alternatives would not. This reasoning reflects the EA's strong assumptions that:

- its proposal would give rise to these outcomes; and
- these outcomes are efficient and give rise to net benefits.

However, we explain in section 7 below that the EA's proposal is not likely to give rise to the outcomes that it expects. Further, section 4 explains why its assessment of the costs and benefits of its proposal is in error and that the costs of its proposals are likely to outweigh the benefits.

Other alternatives are referred to but not assessed

The EA also observes that it does not favour a range of other alternatives that it has considered throughout the course of its earlier consultations and in earlier issues papers. The EA notes that:[176]

> We do not prefer any of the options listed above relative to the current proposal for a variety of reasons, including either because they are not lawful, are not practicable, deliver lower net benefits, or would not further the Authority's statutory objective. On further consideration, we have not changed our assessment of these options discussed in the earlier papers.

As with the four alternative options above, the EA does not subject any of these alternatives to cost benefit analysis, but simply assumes that they would be less preferable. Amongst these elements that the EA rejects out of hand is the potential option to use an LRMC-based charge.

In contrast to this position, the EA has previously observed that, despite its scepticism about the practicality and benefits associated with a LRMC-based charge, these would need to be tested through cost benefit analysis.[177] In our view, this approach to the use of cost benefit analysis is sensible and consistent with the purpose for the tool, as against the EA's use of it in the consultation paper.

[172] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para E.101.

[173] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para E.114.

[174] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para E.123.

[175] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para E.129.

[176] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para E.132.

[177] Electricity Authority, *Nodal prices and LRMC charging*, May 2018, para 8.

6.1.3 Excluding historical investments from the benefit-based charge

Arguably the most controversial aspect of the EA's TPM reform is its proposal to change the allocation of costs for existing transmission investments. This has been a common thread that has linked the EA's proposals, including:

- in its first issues paper, published on 10 October 2012, the EA proposed to apply a beneficiaries-pay charge to assets added to Transpower's regulated asset base from 28 May 2004, as well as pole 2 of the HVDC link;[178] and
- in its second issues paper, published on 17 May 2016, the EA proposed to apply an area of benefit charge to existing investments approved after May 2004 and which had a value of more than $50 million at the time of commissioning, as well as pole 2 of the HVDC link.[179]

Once again, in the current consultation paper, the EA proposes to reallocate the costs of historical investments, without presenting an alternative option that does not do this. However, on the EA's own estimates, excluding historical investments from the benefit-based charge gives rise to net benefits of $18 million. We explain the basis for this estimate in more detail below.

The EA proposes to reallocate the costs of seven existing investments

The scope of existing investments that is included in the EA's current proposal is similar to those that were proposed to be covered by its area of benefit charge in the second issues paper, with the removal of three, being: the upper South Island dynamic reactive support project; the Otahuhu substation diversity project; and the north Auckland and Northland project.

The EA's insistence on reallocation of the costs of existing investments has always been perplexing, given its approach to interpreting its statutory objective with a focus on economic efficiency.

The approach to allocation of the costs of existing transmission investments will always be contentious. Once the investments exist, the allocation of their costs is a 'zero-sum' game between transmission users. Reduced allocation to one user must necessarily imply an increased allocation to another user, such that there is a 'loser' for every 'winner'.

This must be the case because changing the allocation of existing investments provides no prospect of promoting more efficient investment incentives and or achieving more efficient use of the network. Indeed, it is possible that it could instead give rise to increased inefficiency of use, to the extent that the potential for reallocation opens the door for uncertainty about future transmission prices.

There is no support for the EA's approach amongst international regulators. It is notable that even in instances where the EA has been able to cite the use of allocation on the basis of benefits in the United States, these approaches are not applied retrospectively.[180] Nor is this approach approved of by the transmission pricing expert on whom the EA relies, Professor Hogan.[181]

It is not surprising then that the EA estimates the net benefits of its proposal will be $18 million higher if it does not apply its proposal to recover the costs seven major existing investments with benefit-based charges.[182] This result reflects that:

- changing the allocation of costs of existing investments cannot influence the efficiency of transmission investment, and the EA has not demonstrated that it would give rise to any effect on the behaviour of transmission users; and

[178] Electricity Authority, *Transmission pricing methodology: issues and proposal: consultation paper*, 10 October 2012, para 5.6.30.

[179] Electricity Authority, *Transmission pricing methodology: issues and proposal: second issues paper*, 17 May 2016, paras 7.62-7.64.

[180] Electricity Authority, *Beneficiaries-pay in USA*, 20 June 2018, p iii.

[181] Electricity Authority, *Beneficiaries-pay in USA*, 20 June 2018, p 9.

[182] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.172..

- the present value of costs relating to the development, implementation and operation of a benefit-based allocation of the costs of these seven major existing investments would be $18 million.

The EA cites durability of the TPM as a qualitative benefit

However, despite quantifying net costs associated with its proposal to apply benefit-based charges on these seven existing major investments, the EA considers that there is good reason to persist with this aspect of its proposal. It states:[183]

> A future-only application of the proposal would be significantly less durable than the main proposal (which applies to seven historical investments as well as to future investments). This is because it would require some customers to continue paying for existing assets (many of which are relatively recent) from which they do not benefit, while also paying the full cost of future investments from which they do benefit. This could be perceived as unreasonable and so undermine the regime's durability.

It goes on to argue that implementing a future-only version of its proposal would therefore put at risk the net benefits that it estimates, since these might be less likely to be realised if the proposal were not durable.

The concept of 'durability' appears to be of great importance in this context. The EA explains the basis of its understanding of durability in the following terms:[184]

> Apart from the incentive advantages, the Authority regards the benefit-based charge as more likely to be perceived as fair and reasonable than the current approach to spreading the costs of investments across the country.
>
> Over the long-term, pricing arrangements where you 'pay for what you get' would not be contentious (much like the current arrangements for connection charges). As a result, the proposal would lead to more durable transmission pricing arrangements than the existing TPM…

It appears clear from this statement that the EA's view, that its proposal would be more durable than the status quo, stems directly from a subjective belief that its proposal is perceived as fair and reasonable, and would be less contentious than the status quo.

There is no reasonable basis for this belief. The prospect of any change (particularly change that would reallocate the costs of existing investments) to the TPM is always likely to give rise to contention because such changes, by their nature, create winners and losers – as we discuss above. There is simply no evidence that the EA can provide that a benefit-based approach to cost allocation would inherently be viewed as more reasonable by transmission users or by New Zealanders. The unreasonable modelling assumptions that underpin the EA's quantitative assessment of the durability benefit, which we discuss in section 5.2.4 above, amply demonstrate this evidence gap.

The main factor that gives rise to continued contention about the TPM is the foreseeable prospect that the EA might act so as to change the TPM on this basis. This prospect arises not just at the time of the initial allocation, but also with the prospect that there could be further reallocations as evidence emerges about who benefits from an investment. It follows that a far more direct solution to removing contention, reducing uncertainty and improving the durability of the TPM framework is for the EA to commit to limiting the scope of any potential reform to the TPM to be on a prospective basis only – consistent with the approach that is applied in all United States jurisdictions reviewed by the EA.

[183] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.174.

[184] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, paras 3.25-3.26.

6.2 EA assumes that the TPM cannot change under the status quo

The cost benefit analysis that the EA undertakes assesses the costs and benefits that it considers would arise under its proposal as against those that would arise under what it describes as the 'status quo'. In our view, the EA's analysis mis-specifies the status quo since:

- it is proposing a change to the TPM guidelines, under which Transpower develop a TPM; yet
- it assumes that the current TPM that Transpower applies would remain unchanged under the existing TPM guidelines.

6.2.1 EA's proposal is for a change to the TPM guidelines

The proposal set out in the EA's consultation paper is for a change to the guidelines that Transpower must follow in developing the TPM. That is:

- currently, Transpower is required to maintain its TPM in accordance with the existing guidelines, which were prepared by the Electricity Commission;[185] and
- under the EA's proposal, Transpower would be required to develop and implement a TPM in accordance with the guidelines set out in appendix A of the EA's consultation paper (or a subsequently amended version).

There is a distinction between the TPM and the TPM guidelines. Transpower is required to develop a proposed TPM having regard to (amongst other things) the EA's guidelines.[186] The guidelines serve to constrain the scope of the TPM that Transpower can propose.

If the EA introduces new TPM guidelines, it is likely that the EA will request Transpower to submit a proposed TPM having regard to the new guidelines.[187] However, Transpower is not limited to propose a new TPM only when the EA changes the TPM guidelines. Under the Code, it has can submit to the EA a proposed variation of the TPM at any time that is at least 12 months after the last TPM was approved.[188]

The current TPM sends strong charges at peak times. Transpower's transmission pricing data indicates that over the past four years the interconnection charge has varied between $110.35 per kW in 2015/16 and $123.98 per kW in 2017/18. The forecast interconnection charge for 2019/20 is $109.38 per kW.[189]

6.2.2 Transpower has the flexibility to change the TPM under the current TPM guidelines

Under the current TPM guidelines, Transpower need not maintain interconnection charges at these rates. It has flexibility, which it has used in the past, to adjust interconnection charges and the method by which they are recovered to address concerns about the efficiency of price signals.

For example, over 2014 and 2015, Transpower conducted an operational review focused on potential inefficiencies with price signals sent by the TPM at that time.[190] The result of the review was changes to the TPM to improve the efficiency of price signals for the interconnection and HVDC charges. Box 6.1 below summarises the drivers and outcomes of the review.

[185] Electricity Commission, *Guidelines for Transpower transmission pricing methodology*, 24 March 2006.

[186] Electricity Industry Participation Code, section 12.89(c).

[187] Electricity Industry Participation Code, section 12.88.

[188] Electricity Industry Participation Code, section 12.85.

[189] Transpower, *Transmission pricing data for 2019/20 pricing year*, undated. Available online at https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Rates%20Table%20April%202019.pdf, accessed 28 August 2019.

[190] A second operational review initiated by Transpower 2017 was discontinued

Box 6.1: Transpower's first TPM operational review, May 2014 to August 2015

Transpower initiated its first operational review of the TPM on 21 May 2014. It identified several potential problems with the TPM at that time, including that:[191]

- price signals sent by the interconnection charge in the upper North Island (which were designed to reflect future investment need) may be inefficient, since enhancements to capacity had recently been completed;
- price signals sent by the interconnection charge in the lower South Island are unstable due to variability in demand at the Tiwai smelter, but these movements do not reflect future investment need;
- price signals sent by the historic anytime maximum injection (HAMI) charge for the HVDC were causing problems.

Transpower explained in its second consultation paper that it was concerned about the strength of the interconnection charge in the upper North Island and upper South Island, which at the time were determined on the basis of demand during 12 peak periods. It highlighted the risk that too strong a charge would promote peak avoidance, including costly investment in avoidance capability which would not be warranted by any transmission-deferral benefits.[192]

It also explained that it was concerned with the HAMI charge because, by setting charges associated with highest injection, it created a very high cost for South Island generators with setting a new peak. Transpower cited statements by Contact Energy and Meridian Energy that the HAMI charge acts to discourage them from operating their generation plant at full capacity at times when this might result in exceeding the existing HAMI limit.[193]

In February 2015, Transpower proposed variations to the TPM, some of which were approved by the EA in July and August 2015, to take effect in the pricing year commencing 1 April 2017. Outcomes of the review included:[194]

- to increase the number of peak periods used to calculate the RCPD charge in the upper North Island and upper South Island from 12 to 100; and
- to replace progressively the HAMI charge for the HVDC link with a mean injection charge based on the previous five years injection.

The process and outcome of the first operational review demonstrates the flexibility that Transpower has, within the current TPM guidelines, to change the strength of the interconnection charge and the means by which charges are recovered. The problems that Transpower confronted in its operational review are very similar to those that the EA is now grappling with in its review of the TPM guidelines.

It follows that, in evaluating the costs and benefits of changing the TPM guidelines, the EA should assess the costs and benefits that would result from changing the current flexibility that Transpower has to determine the TPM under its current guidelines. That is, the appropriate factual (or status quo) scenario, is not necessarily a continuation of the current level and basis for charges, but should reflect Transpower's ability to change the TPM to address inefficiencies within the scope of the current guidelines.

[191] Transpower's website, https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/operational-review-1, accessed 28 August 2019.

[192] Transpower, *2014/15 TPM operational review: second consultation paper*, 13 November 2014, pp 26-27.

[193] Transpower, *2014/15 TPM operational review: second consultation paper*, 13 November 2014, p 45.

[194] Transpower, *TPM operational review: decisions summary*, August 2015.

Yet, on our understanding, this is not what the EA's cost benefit analysis achieves. In its assessment of the benefits of increased grid use, the EA has assumed the continued application of highly concentrated peak transmission charges, and concluded that:

- the removal of these charges would increase consumption in peak periods, which it considers would give rise to increases in consumer surplus – see section 3.1.3 above; and
- the continuance of these charges would give rise to incentives for inefficient investment in batteries so as to avoid the charges – see section 3.1.5 above.

Figure 6.2 below illustrates this situation graphically. The current TPM guidelines are indicated as an area within which Transpower can propose a TPM, and the current TPM as a point within this area.

Figure 6.2: Current TPM is formulated within guidelines that the EA proposes to change

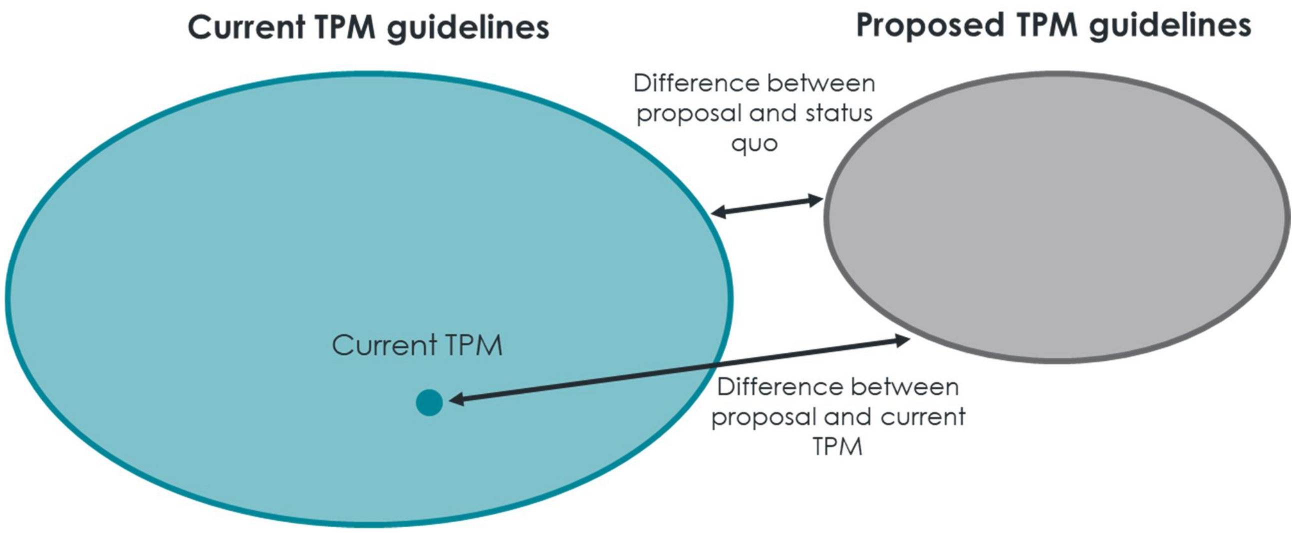


Figure 6.2 shows that, although the EA's cost benefit analysis assesses its proposal against a status quo in which the current TPM continues to apply, the difference between the net benefits arising from its proposal and future TPMs that Transpower could formulate under the current guidelines in response to emerging inefficiencies may be much smaller.

7. Benefit-based charges assumed to be efficient

The cost benefit analysis assumes that the prospect of benefit-based charges sends a cost-based price signal that will elicit changes in behaviour from customers, giving rise to both efficient utilisation of, and efficient investment in, the transmission network. These assumptions are unlikely to be justified. In our view, there is little reason to expect:

- that price signals sent by benefit-based charges would be perceived or understood by customers;
- that benefit-based charges would send efficient price signals to customers; or
- that customers would respond to those signals with the desired effect.

We explain the basis for these views in more detail below.

7.1 Benefit-based charges aim to address problems with postage-stamp cost recovery

The benefit-based charge is aimed at addressing the problem that, under a postage-stamp charge, transmission users do not fully internalise the costs their use of the network places on other users. If this use drives new network investment, the costs of this investment are recovered from all users rather than from those who gave rise to the need for the investment.

In principle, this problem could lead to over-investment in the network, driven by price signals that are too weak to discourage use of the network in congested areas. The benefit-based charge is intended to reduce or eliminate this effect by allocating the costs of new investments to the users who benefit from them.

This problem, and the nature of its anticipated solution, is described explicitly by the EA in its consultation paper:[195]

> One of the other main expected benefits of the Authority's proposal is more efficient investment by both generation and large loads. Under the current TPM, these parties do not face the full costs of any required upgrades to the interconnected grid when making location decisions. As their marginal private costs are lower than marginal social costs, the decisions of these parties may not lead to results that are efficient for society as a whole.

The central thrust to the EA's problem statement is that transmission price signals sent by a postage stamp charge are not precise. Postage stamp pricing results in an averaged price signal being sent which:

- for users in relatively constrained areas may be lower than the marginal costs that their use of the network may impose on others; and
- for users in areas with excess capacity may be higher than the marginal costs that their use of the network may impose on others.

It follows that there could be benefits in a more bespoke charge that would better signal to transmission customers the costs that their usage would impose on the network. Whether such a charge would give rise to net benefits would depend on:

- its effect in driving changes in behaviour, taking into account that it also may also change behaviour in ways that are not desirable; and
- the magnitude of the problem that it is intended to address, as against the administrative costs associated with its formulation, implementation and operation.

[195] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 39.

It is not clear that the EA's benefit-based charge meets the requirements for this more bespoke charge, since it is levied on the basis of benefits, rather than of costs.

7.2 It is unlikely that a benefit-based price signal will be transmitted to users

Underpinning the EA's view that the introduction of a benefit-based charge will give rise to net benefits is its conviction that generators and large loads will change their behaviour in response to this scheme. The means by which the EA expects that this change in behaviour will be achieved is unusual and deserves close scrutiny.

The EA's proposed benefit-based charge will not send a conventional price signal to ration use of the transmission network. Instead, users will be expected to ration their use of the transmission network in response to the prospect of future increases in price – which the EA has previously called a 'shadow price'. Box 7.1 below explains how these different mechanisms work.

Box 7.1: The EA expects benefit-based charges to send a 'shadow price' signal

In a conventional market setting, price is the signal that consumers respond to, and which is used to ration demand. For example, in a perfectly competitive market, where prices are equal to marginal cost, then:

- when marginal cost increases, price increases commensurately and consumers who place a lower value on the service will use it less or cease to use it entirely; and
- when marginal cost decreases, price decreases commensurately and consumers who place a higher value on the service will use it more or begin to use it, if they had not previously.

In this stylised example, changes in the price sends an accurate signal to users about the cost of production and users respond efficiently to this signal.

The EA's benefit-based charge will not send a conventional price signal. Once the costs of a new investment are allocated to users, they will be recovered using a fixed charge. The imposition of a fixed charge would not be expected to give rise to any significant behavioural change, at least in the short term.[196]

Rather, the EA expects that behavioural change amongst users will be stimulated by the prospect that they will be allocated some of the costs of a future investment. In response to this threat, the EA surmises that generation and large load may review and potentially reduce their use of the grid at peak times, in turn giving rise to a reduced prospect of the investment proceeding.

Through this mechanism, the EA assumes that transmission users will change their behaviour *now* in response to the prospect of *future increases* in their transmission charges. This concept was labelled by the EA in its 2016 consultation paper a 'shadow price', although this phraseology is now absent from its current proposal.

The EA's rationale for introducing benefit-based charges appears to rest upon an assumption that, through their design, they will be capable of achieving both static and dynamic efficiency. That is:

- the price signal sent for additional use of the grid within its existing capacity reflects short run marginal cost (approximately zero); and
- the shadow price signal sent for additional use of the grid that would give rise to expansion reflects LRMC.

[196] This is because in most cases, it might be reasonable to assume that the surplus that transmission users gain from their use of electricity exceeds the additional costs they have been allocated from the new investment.

In our view there is little reason to presume that transmission users could accurate or precisely discern a shadow price signal. To believe otherwise assumes that:

- users can discern how their behaviour affects the prospects of a grid upgrade and that consumption below a 'bright line' level will not be affected by the prospect of future charges;
- users can understand how their benefits will be assessed in distributing the costs of an investment and how changes to their actions will affect this distribution; and
- users can anticipate the actions of other users and take these into account in determining their own actions in responding to the shadow price signal.

In reality, none of these assumptions about the ability of users are likely to be true. Even if they were true 'in expectation', users may face a great deal of uncertainty as to the impact of their behaviour on future charges.

7.2.1 Users are unlikely to be able to discern how their behaviour affects grid costs

The EA's proposal assumes that transmission users will determine their behaviour taking into account the effect that their choices have on grid investment costs. However, most users of the transmission network are unlikely to be able to understand exactly how their actions affect the prospects or costs of grid upgrades.

The processes that Transpower goes through to determine its grid investment program are complex and it is unrealistic to expect that even large users would have a detailed understanding of how changes in consumption behaviour might affect this program. It follows that most users do not understand the effect that their behaviour has on costs, and that they are therefore incapable of internalising these costs in their behaviour in the way that the EA assumes. Even if Transpower could potentially provide this information to users, there is no reason to expect that it would be provided in a timely way so as to support user decision-making.

This is why conventional approaches to utility pricing use a price signal – consistent with the outcomes of workably competitive markets – to explicitly signal the costs that users' behaviour will be expected to have on the costs of providing the service.

7.2.2 Users are unlikely to be able to understand how their actions affect their allocation of costs

The EA further assumes that users understand how their actions would affect their allocation of costs. However, even if users could understand how their actions would affect grid costs, it does not follow that they would also understand the method for determining beneficiaries.

Transpower must implement both a 'standard' and a 'simple' method for assessing the beneficiaries of an investment – and use these estimates to allocate the costs of the investment in proportion to the positive benefits. These methods are likely to be complex and not easily understood or applied by other parties. By way of example, the vSPD method that the EA requires Transpower to adopt for the allocation of the costs of the seven major existing investments involves the application of a complex empirical model. Most users are unlikely to allocate sufficient resources to be able to undertake the type of modelling necessary to assess the impact of their behaviour on their allocation of future costs.

For customers to be able to engage with and respond to the signals they receive, they need to be able to understand how their actions change their payments – that is, to comprehend a 'price' for their actions. There is little reason to believe that such a price will be readily perceived by transmission users under benefit-based charges.

7.2.3 Users will face considerable uncertainty as to the actions of others

Interconnection assets, by definition, have multiple users. Even for users that both understand how their actions affect costs and the allocation of these costs, there is likely to be a great deal of uncertainty about these aspects given the potential for the actions of other users of the interconnected network to change.

This uncertainty could be expected to give rise to a wide range of potential 'prices' associated with change in behaviour. In practice then, even sophisticated users could have little certainty about how their behaviour would be reflected in charges.

In these circumstances, it appears optimistic to conclude that users would respond to this uncertainty with efficient responses.

7.3 An accurate shadow price would not send efficient price signals

In support of its proposal, the EA states (amongst other things) that the prospect of a benefit-based charge for a new investment provides an incentive to a user to reduce its use of the transmission asset. It explains that the efficiency of this response rests on the assumptions that:[197]

- the saving in charges is the same as the grid costs saved; and
- the user permanently changes its usage in anticipation of the additional charges.

We agree that these assumptions are a necessary condition for benefit-based pricing to give rise to the efficient outcomes that the EA anticipates. However, even if users were capable of discerning an accurate and precise shadow price, it does not necessarily follow that this would elicit efficient responses. In particular:

- the costs of shared new investments will not be fully internalised by users; and
- any behavioural change is unlikely to be sustained once the assumed shadow price dissipates.

7.3.1 Costs of new investments will not be fully internalised by users

The EA characterises its proposed benefit-based charge as ensuring that generation and large loads would 'face the full costs' of any required upgrades: [198]

> …a TPM issued under the proposed guidelines would provide generation and large loads with the incentive to take account of the costs of any such required upgrades. This is because they would face the full costs of any required upgrades to the interconnected grid, through paying the benefit-based charge. Over time, the Authority expects this to result in lower total costs of grid investment.

If this characterisation is intended to convey the concept that, under the benefit-based charge, generation and large loads will fully internalise the social costs of their actions, then it is incorrect.

Assuming that the 'shadow price' works (although we consider that this is unlikely for the reasons set out above) the price signal sent to transmission network users would usually be expected to be weaker than one which would be sufficient to internalise the social costs of their actions where there is more than one user of the transmission investment. This is known as the 'tragedy of the commons'.

The benefits of any investment will likely accrue across all users of the investment, and therefore the costs of the investment will be recovered across these users. It follows that under benefit-based charges, no single user (even a user whose actions may give rise to the need for the investment) will internalise the full cost of the investment in its decision making. The greater the number of users of an investment, the lower the weight that each user will give to the impact of its actions on the likelihood of an investment proceeding and therefore the costs imposed on others.

This can be contrasted against the ability of a peak charge (such as the RCPD or LRMC-type charge) to signal to users the incremental cost of their usage irrespective of the number of other users of the transmission investment.

[197] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 220, fn 366.

[198] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 39.

One reason for this unsatisfactory result is that an approach to assessing benefits can inevitably only capture the benefits that are accrued in the electricity market – and potentially not even all of these. Generators and large loads make locational decisions for many reasons that have nothing to do with the price of electricity or the costs of transmission, and the benefits that underpin these reasons cannot be accurately or reliably captured by Transpower or any other party.

For example, the benefits associated with reliability provided by transmission investments are not assessed by the EA under the vSPD method that it applies to allocate the costs of the seven historical investments. Despite not proposing a method that captures the benefits of reliability, the EA nonetheless assumes that Transpower will be able to do so. This appears to reflect an assumption that the benefits will, or can be, appropriately assessed by Transpower.

The EA acknowledges that the issues associated with the 'tragedy of the commons' at appendix E of its consultation paper. It states that, with many small users, each user's private calculation differs from that of a single user, and will not take account of:[199]

- the savings in transmission investment that could be achieved if users took collective action to reduce their future demands on the grid;
- the benefits that could be realised if users took collective action to increase their future demands on the grid; and
- associated changes in nodal prices.

Despite this, the EA's rationale for reform assumes this internalisation effect occurs. For example, we note in section 6.1.2 above that, in rejecting alternative proposals from its consideration, the EA cites that these approaches would not ensure that grid users would make usage and investment decisions taking into account the impact of those decisions on grid investment.

7.3.2 Behavioural change is unlikely to be sustained once shadow prices dissipate

The EA assumes, in computing the costs and benefits of the benefit-based charge, that behavioural change achieved by shadow price signals is sustained. However, any shadow price signal sent in respect of a future transmission investment lasts only until the investment is made.

To implement any benefit-based charge, Transpower will need to determine a period over which to estimate benefits. This raises the prospect that behaviour during this period could be temporarily distorted by users with the intent of reducing their allocation of costs for the new investment, rather than as an efficient response to costs. This behaviour would then revert once the investment was made.

The EA also acknowledges this concern but states that the "proposed guidelines require Transpower to design the TPM to limit these inefficiencies as far as is reasonably practical".[200] However, the EA does not describe how, in practice, Transpower might be able to achieve this result or identify whether it would be practicable.

7.4 Benefit-based charges would give rise to inefficient use of the grid

The EA assumes that its proposal would have the virtue of sending efficient price signals about the costs of future investment while also not inefficiently reducing use of the grid during times at which network investments are not imminent.

In our view, even if the shadow price were effective in sending a signal to users, the proposal would not give rise to the efficient use responses that the EA assumes because:

[199] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 219.

[200] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, p 220, fn 366.

- the shadow price signal cannot be perfectly observed by users and they will therefore respond with reduced consumption even at times or in places where that is not an efficient response; and
- the fixed charges that are used to recover past benefit-based investments are likely to be periodically updated to reflect changes in use and this will result in users responding to the prospect of these revisions.

We set out the basis for these views in more detail below.

7.4.1 Effective benefit-based price signals may not differ greatly from an LRMC charge

The EA assumes that the proposed benefit-based charge is superior to other means of signalling the costs of new transmission investments. It makes this assumption largely because it omits careful consideration of the mechanics by which the charge would be developed and applied.

This shadow price approach can be contrasted with a more conventional approach to utility pricing. When a regulator or utility wishes to signal the prospect that increased usage could give rise to future costs, this is often achieved through a price that reflects those future costs – for example, an LRMC charge.

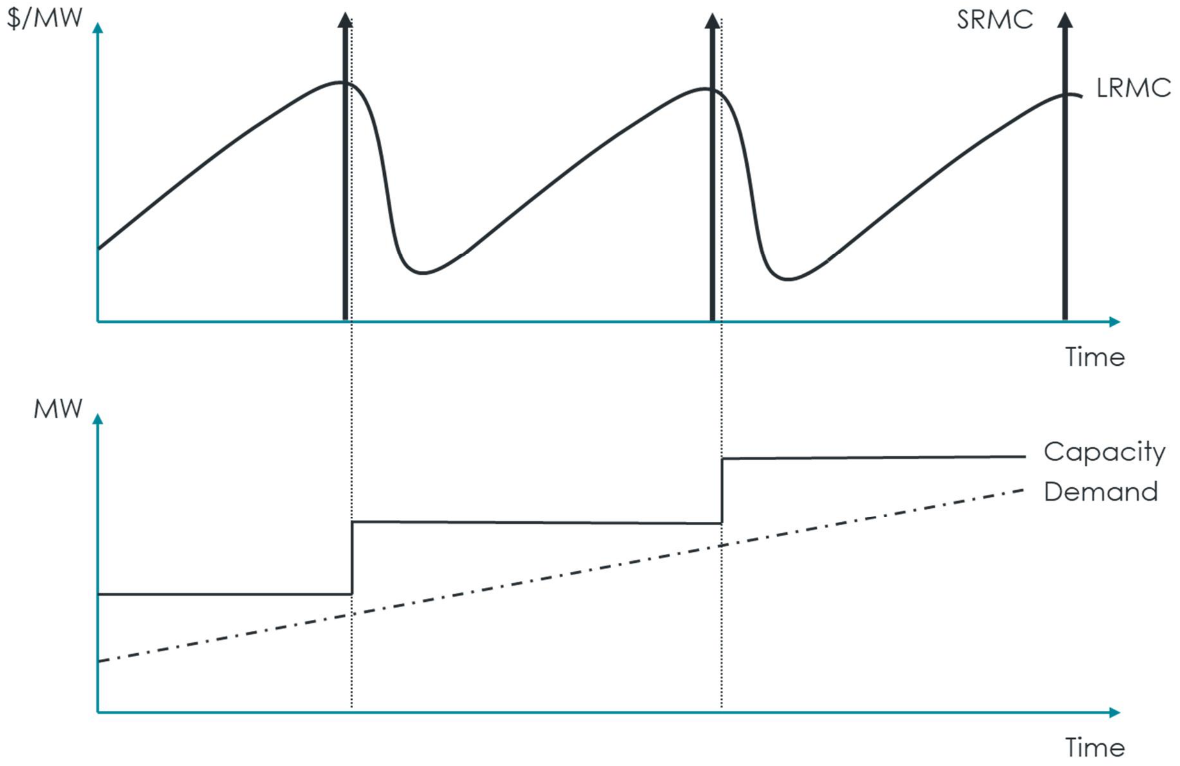
The EA is highly critical of LRMC charges because it considers that they often send price signals that result in inefficient use of the grid. It states:[201]

> The LRMC charge only has an effect on demand when it is more than the default nodal price, and it has more effect the lower the default nodal price. In these cases it reduces the use of the grid to below capacity. That is, it inefficiently reduces use of the grid. In particular, if demand is in fact never going to reach the investment trigger point, then the LRMC charge would be highly inefficient because it would reduce demand for no reason at all.

The typical pattern of LRMC charges is shown at figure 7.1. The figure shows how the LRMC price signals change over the investment cycle, rising immediately prior to an investment and falling again afterwards. The figure also indicates SRMC as a very high positive cost occurring immediately prior to augmentation.

[201] Electricity Authority, *Nodal prices and LRMC charging*, May 2018, para 83.

Figure 7.1: LRMC prices change over investment cycles



Source: HoustonKemp

The EA's concern about inefficient use relates to the relativity of SRMC and LRMC. The SRMC of network use might be very low (almost zero and much lower than LRMC) until shortly prior to an investment, at which time it can be expected to increase to well above the LRMC. It follows that, from the perspective of static efficiency, an LRMC charge:

- sends too high a price signal most of the time; but
- sends too low a price signal immediately prior to an investment in new capacity being triggered.

However, having regard to the mechanism through which a benefit-based signal would be sent, we consider that a shadow price signal (if it could be perceived by users) would behave in much the same way as the LRMC charge that the EA criticises. This is because:

- users will likely be uncertain about where any 'trigger point' for an investment is;
- users will likely be uncertain about how their actions affect benefits and how benefits would be allocated to them;
- users will likely be uncertain about the actions of other users and how these could affect the prospect of any investment or their allocation of costs.

The practical upshot of these substantial uncertainties is that users will not perceive a sudden and strong shadow price signal immediately prior to when an investment would occur. It is much more likely that users will begin to respond to a shadow price signal a long time before an investment would occur, and that this signal will gradually strengthen as the prospects of an investment going ahead increases.

It follows that users will respond to this shadow price signal by reducing their consumption in periods in which it would not be efficient to do so. There is little reason to believe, even if a shadow price signal could be perceived by users, that it would work in a way that is more efficient than under an explicit peak charge. The most important difference is that, with a peak price, there is a clear price signal that can be interpreted and responded to by users in a predictable way, whereas the potential response to a shadow price signal is highly uncertain.

7.4.2 Fixed charges will send marginal price signals

The proposed TPM guidelines require Transpower to recover benefit-based cost allocations as fixed charges. As with the residual charge, this approach reflects the EA's concern that setting charges on consumption or demand could send signals to inefficiently reduce consumption.

However, applying charges on a fixed basis does not resolve this issue and users will still effectively receive marginal price signals, at least over the medium term.

This effect arises because fixing charges for transmission users over a long period of time is not durable. Use of transmission facilities would be expected to change over time, and benefits would change with this. It follows that, under benefit-based pricing, the basis for determining the allocation of costs prior to an investment proceeding would be undermined over time.

The EA also holds this view, which it expressed in the first issues paper:[202]

> The approach proposed by Professor Hogan of applying beneficiaries pay involves determining the charge that would apply to parties prior to an investment, with the charge fixed over time. Although this approach has some merits, the Authority considers that a key difficulty with such a charge is it is calculated on the basis of anticipated benefits rather than actual benefits. This creates a risk for efficient investment as parties will be reluctant to invest if they may continue to be subject to a charge even though they no longer benefit from the investment. This could adversely affect competition, and does not take into account new entry.

Presumably to address these issues, the EA's proposed TPM guidelines include provisions that allow Transpower to review the allocation of benefit-based charges in circumstances in which:[203]

- there is (or will be) a 'substantial and sustained' change in grid use affecting benefits derived by transmission users from a benefit-based investment; and
- this change in circumstances was not factored into the calculations used to allocate the relevant charges.

These provisions are entirely sensible, given the lack of durability of fixed benefit-based charges. However, these clauses mean that charges are not truly fixed, and over time will change to follow use. This gives rise to the prospect that users will continue to respond to implicit price signals to restrain use in anticipation of future redetermination of benefit-based charges. The implications of this is that fixing charges will not, by itself, prevent changes of behaviour in response to the imposition of transmission charges.

[202] Electricity Authority, *Transmission pricing methodology: issues and proposal: consultation paper*, 10 October 2012, paras 5.6.64-5.6.65.

[203] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, Appendix A: Proposed TPM guidelines, 23 July 2019, para 26.

8. No support for reform in the near term

If we were to disregard the concerns raised in sections 4, 5, 6 and 7 above – and accept the results of the EA's cost benefit analysis – these results on their own merit do not support the EA's proposed change to the TPM guidelines in the near term. This is because:

- the EA's cost benefit analysis shows that the benefits of the reform occur towards the end of the modelling period; and
- in any case, many of the benefits predicted by the EA depend on speculative future developments.

Disaggregating the time series of benefits from the EA's cost benefit analysis, we show that the greatest net benefits are achieved if the proposal is implemented so as to come into effect in 2034. This timing gives rise to net benefits that exceed immediate implementation of the EA's proposal by $87 million in present value terms.

Caution regarding the uncertainty of future developments, and the results of the EA's cost benefit analysis itself, suggest that efficient operation of the industry would be promoted by a slower implementation of the proposal than is being considered by the EA.

8.1 Benefits of the reform are modelled to occur towards the end of the period

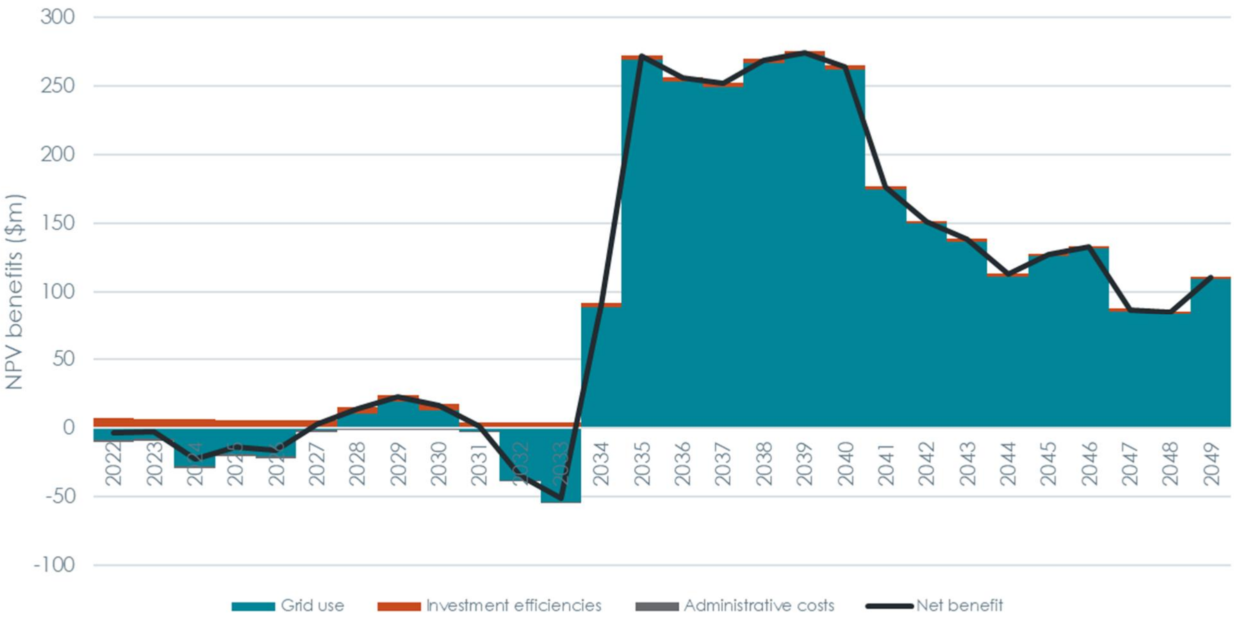
According to the EA's analysis, the annual net benefits of the reform are projected to be near zero until 2034, rising sharply thereafter due to a collapse in the off-peak wholesale price modelled under the proposal.

By extracting the annual present value of benefits attributable to the proposal from the EA's grid use model, which covers 96 per cent of all projected benefits, and annualising investment efficiency benefits and administrative costs, we have obtained an estimate of the time series of annual present value of benefits attributable to the proposal.

Figure 8.1 below shows this time series of the net benefit estimated by the EA to arise under the proposal over the modelling period. Two observations follow from the figure:

1. The annual net benefits of the reform are projected to be near zero, and fluctuate between small negative and positive values until 2034. In fact, the cumulative net benefits predicted by the cost benefit analysis are negative until 2034.
2. There is a huge increase in projected benefits after 2034, to which the entirety of the predicted total net present value of benefits in the EA's cost benefit analysis is attributable.

Figure 8.1: Net present value of benefits under the EA's proposal, 2022 to 2049



Source: Electricity Authority

The noticeable upswing in the projected benefits of the reform after 2034 is almost entirely due to a huge increase in the consumer surplus under the proposal, driven by a collapse in off-peak wholesale prices to $40/MWh – the lower bound under the EA's pricing methodology, as we set out in table 5.1 above.

The collapse in off-peak wholesale prices under the proposal is due to six low cost generators, four wind and two hydro, which are projected by the EA to come online between 2032 and 2034 under its proposal and flood the off-peak wholesale market with offers. None of these generators enter the market under the status quo.

Table 8.1 contains the SRMC and offered capacity during the off-peak period for these six generators. The 495 MW of off-peak capacity offered by these six generators represents an 11 per cent increase in capacity over the 4406 MW offered by all existing generators in 2032.

Table 8.1: Generation build under the proposal, 2032 to 2034

Year	Name	Type	SRMC ($/MW)	Off-peak offer (MW)
2032	CastleHill_s1	Wind	3.21	78.80
2032	HawkesBayW	Wind	3.21	88.65
2033	CastleHill_s2	Wind	3.21	78.80
2033	CastleHill_s3	Wind	3.21	78.80
2034	Clarenc	Hydro	0.92	35.00
2034	Clarenc54	Hydro	0.92	135.00

Source: Electricity Authority

This substantial increase in low cost generation after 2034 pushes down off-peak prices under the proposal to such an extent that they become constrained by the price floor of $40/MW in the EA's pricing mechanism for the rest of the modelling period, with the exception of 2047 and 2048.

As more than half of modelled demand is in the off-peak period, the collapse in off-peak prices under the proposal leads to significantly higher consumer surplus after 2034 than under the RCPD, which is captured by the EA's cost benefit analysis as benefits attributable to the proposal.

This dynamic leads to sustained positive net benefits after 2034 in present value terms, upon which the positive total net present value of benefits predicted by the EA's cost benefit analysis depends.

8.2 Benefits relied upon by the EA are speculative

Many of the benefits that the EA relies upon in its assessment of its proposal are conditional on the success of future changes in the New Zealand electricity industry that are yet to occur.

In particular, the EA assumes that mass market consumers will respond to the removal of the RCPD price signal. It justifies this assumption by reference to:[204]

- increased cost reflectivity of distribution pricing, which it expects to result from reforms in this area;
- emerging business models that will manage wholesale and network price risk on behalf of consumers;
- emerging technology which will facilitate real-time demand response by consumers and allow for more efficient exploitation of arbitration between electricity prices at different times of day; and
- changes to market design through the introduction of real-time pricing, which is expected to support real-time demand response.

Similarly, the benefits the EA attributes to more efficient investment in distributed generation in the form of batteries is highly dependent on the assumption that battery costs will continue to fall precipitously.

We offer no opinion as to whether any of these outcomes are likely to arise in the future. However, it is clear that the success of the EA's reform rests upon speculation that these outcomes will arise relatively early in the modelling period.

8.3 Reform should be postponed until 2034

When considered in combination with the speculative nature of the benefits identified by the EA, the time profile of the net benefits that it estimates strongly suggest that any reform should be postponed until 2034. Reform at this time would:

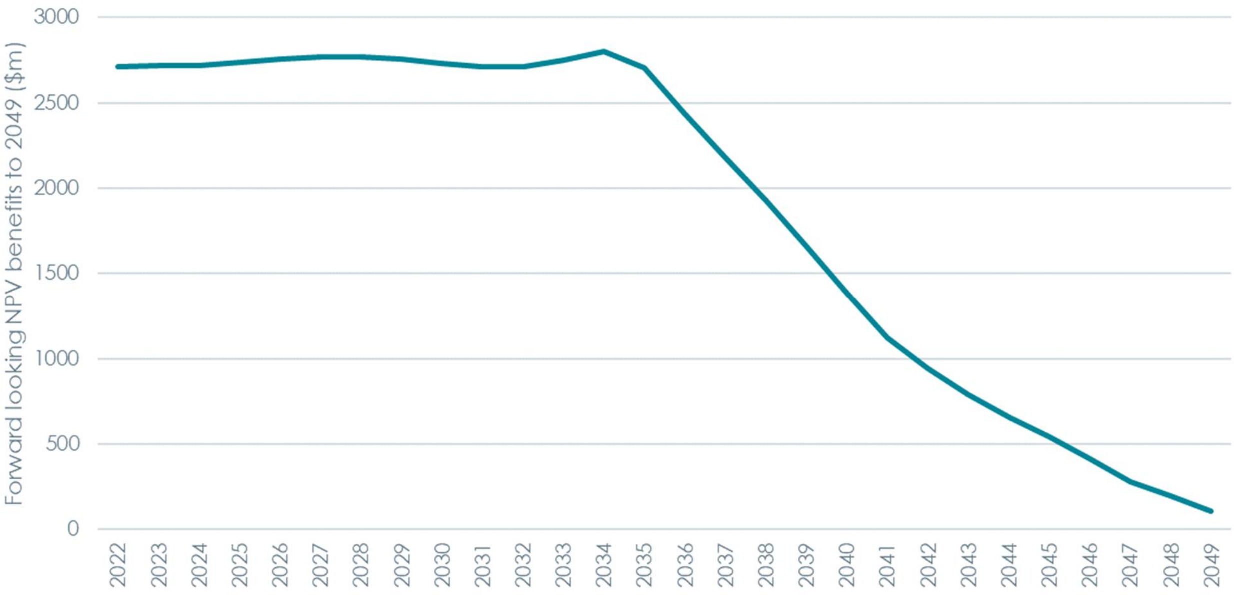
- maximise net benefits of the EA's proposal, based on the cost benefit analysis; and
- provide time for assumptions that the EA makes about the efficacy of future reforms and technologies to be proven, rather than assumed.

The net present value of benefits due to the proposal fluctuates around zero until 2034, with a cumulative net present value of -$87m by 2033 and is uniformly positive thereafter. It follows that the timing of the EA's proposal that gives rise to the greatest net benefit under its cost benefit analysis is 2034.

Implementation of the proposal by 2034 would give rise to net benefits that exceed immediate implementation by $87 million in present value terms. This gives rise to total net benefits of $2,798 million, as compared to $2,711 million estimated by the EA in connection with immediate implementation of its proposal. Figure 8.2 shows the total forward looking net present value of benefits due to the proposal for each year of the modelling period.

[204] Electricity Authority, *2019 issues paper: transmission pricing review consultation paper*, 23 July 2019, para 4.44.

Figure 8.2: Total forward looking net present value of benefits by year of implementation



Source: Electricity Authority

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Review of the Electricity Authority's TPM Third Issues Paper

Creative Energy Consulting Pty Ltd

September 2019

Executive Summary

Nodal Prices on their own do not promote Efficiency

The EA has established a principle that nodal pricing is "best", in the sense of promoting efficiency, but this appears to relate to an aspirational ideal rather than an assessment of current price outcomes. So, a better principle would be that nodal prices would *ideally* be the best way to promote transmission efficiency. That principle means that the EA should continue to identify and develop ways to move closer to this goal.

The TPM design must reflect the world as it is, not as we would like it to be. The EA should acknowledge that nodal prices are *not* fully efficient and are not likely to be for the foreseeable future. It must develop a TPM that reflects that fact and addresses that gap. That means, at the very least, providing for effective and flexible transitional arrangements so that administered transmission prices can continue to fill the gap between the *ideal* and the *actual* nodal price outcomes.

Beneficiary-Pays Charges do not promote Efficiency

Charging based on a beneficiary-pays (BP) approach does not promote efficiency in user investment decisions, due to problems of dilution and opacity. Dilution, because the pricing signals provided by BP charges in this situation are likely to be a fraction of the long-run transmission cost. Opacity, because it will be impossible for most parties to predict these future BP charges in any case.

Instead, the EA should draw on the implications of its "nodal prices are efficient" principle. Because if nodal prices *are* efficient – even if only in a conceptual and unrealizable framework – then efficient transmission prices should have similar characteristics, albeit with their volatility removed to make them useful signals for investment. Whilst modelling the nodal prices themselves would be complex, developing a heuristic method which gives similar outcomes should be possible. The "tilted postage stamp" is an example of this approach.

When the entry of a new generator or large load is likely to prompt immediate and nearby "shallow" transmission investment, even these idealised nodal prices might not be efficient, due to problems of "lumpiness". These situations could be dealt with through a regime of "deep connection charging", where one-off charges are levied on the new entrants, reflecting the cost of the shallow investment that they prompt.

Residual Charging is a Standard Problem with a Standard Solution

In contrast to the challenge of creating dynamically efficient pricing signals, the problem of residual charging is straightforward and generic. The same problem is faced by transmission owners and regulators around the world, because the fundamental economics of transmission mean that efficient prices alone will not recover the necessary revenue.

Rather than learn from overseas best-practice – and even best-practice in NZ – the EA has developed its own unique ideas. These fail to apply the standard Ramsey principles, and instead rely on retrospectivity and price discrimination to minimise user response to residual charges.

Pricing must be Stable, Transparent and Predictable in order to be Durable

As is said of the court system, justice must be *seen* to be done. Similarly, for durability, transmission pricing must be *seen* to be reasonably and equitable. Three critical elements are needed for this; the TPM must:

- be intuitively reasonable; essentially, the EA's "what you pay is what you get" requirement;
- offer a clear trajectory given the expected future; and
- have sufficient flexibility and adaptability to remain intuitively reasonable even when the future departs from what was expected

But the EA's proposal has none of these elements. The BP regime is not intuitively reasonable because it only logically applies to future assets, whereas transmission services are provided by *all* assets. It does not provide a clear trajectory, because this depends upon unknowables such as when and where investment will occur, and how and to whom the benefits from these investments will be attributed. It is not adaptable because the methods are highly prescriptive and create charges that are frozen in time and not permitted to adapt to unforeseen changes in transmission usage and flows.

The EA offers some fixes to mitigate these fundamental flaws. It proposes to include some historical assets in its BP regime. It places controls on year-on-year price changes. And it offers Transpower some discretion to re-open various frozen charges. These compromises are *ad hoc*, inconsistent and arbitrary; simply papering over the cracks of an unsustainable methodology.

The EA has not followed the Example of the US

The EA has argued, and continues to argue, that an important benefit of BP charging is that it improves the effectiveness of transmission planning, by encouraging useful user engagement in the process. To my knowledge, the EA is alone in considering this a material factor in TPM design, and still fails to offer any quantitative evidence to support its position.

In the latest issues paper, the EA has described BP practices in the US and argues that these provide support for its position. But this is to misunderstand the US approach and context, which is to allocate costs between transmission *companies*, not *customers;* a process that has no relevance to NZ, with its single transmission company.

The US context has shown BP charging to be complex and contentious, particularly in the choice of method and assumptions. But applying it to transmission pricing – as the EA proposes - would raise new challenges which the US has not had to face: whether and how to apply BP charges to new customers who were not present or anticipated at the time that the investment decision was made. The EA has not satisfactorily addressed this dilemma, either conceptually or practically.

The Proposed TPM is Discriminatory and Anti-competitive

In its relentless pursuit of "efficiency" in transmission usage and investment, and its fixation on BP approaches, the EA has neglected some basic principles of transmission pricing: non-discrimination, transparency and stability. In doing so, it has developed TPM proposals that are discriminatory, arbitrary and also inconsistent with the competitive leg of the statutory objective.

The EA has not followed its own Principles or Arguments

The latest issues paper contains some useful and interesting discussion around the role of nodal prices, the need for long-run price signalling, the importance of equity and non-discrimination, and the application of beneficiary-pays in the US. The problem for the EA is that none of these discussions, or their conclusions, point to the need for beneficiary-pays charges as the core of a new TPM. On the contrary, they show up its flaws and inconsistencies. It seems like the EA has long settled on this solution and now ignores its own arguments where they point to alternative approaches.

The EA should go back and read its own issues paper, and follow the ideas and insights contained therein to their logical conclusions: that if nodal prices are efficient, efficient transmission prices should have similar characteristics; that if the EA is forced, against its own principles, to have retrospective BP charging, then its own principles are flawed; that if charges are to be non-discriminatory and equitable, they must be variable, not fixed; and that if the US – as the home of beneficiary pays – has not incorporated BP into transmission pricing, perhaps it is not appropriate for NZ either.

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1 INTRODUCTION

1.1 ENGAGEMENT

Creative Energy Consulting (CEC) has been engaged by Trustpower to review the Electricity Authority's (EA's) consultation paper "Transmission pricing methodology: issues and proposal, third issues paper", dated 23rd July 2019[1]. I, David Smith, am the director of CEC and the author of this paper.

In previous engagements, I developed my knowledge and understanding of the various concepts and methods introduced in the Transmission Pricing Methodology (TPM) review and have brought that experience into this current work. Whilst much of the comment and discussion in my three earlier reports[2] remains relevant, I have endeavoured to avoid repeating myself in this latest report, preferring to focus on the new ideas and issues that the EA has introduced in its latest paper. In this respect, my four reports need to be taken together provide a complete and comprehensive commentary on the EA's review process, design concepts and latest proposals.

1.2 EXPERIENCE

I have been involved in transmission pricing specifically, and electricity market reform generally, for over thirty years, with projects spanning markets in New Zealand, Australia, the UK, the US and China. Across this diversity of geographically and regulatory characteristics, I have always been guided by two tenets. That transmission pricing is necessarily and appropriately customized to the characteristics of each particular market. And that, nevertheless, there are some generic, fundamental principles of good pricing design that are always relevant and important.

1.3 DISCLAIMER

This report presents the views of myself and my company, CEC, and does not necessarily, and is not intended to, represent the views of Trustpower.

1.4 WHAT'S NEW

As the table on pp80-81 of the Issues Paper makes clear, the TPM guidelines proposed in this third Issues Paper ("the Issues Paper") are not fundamentally different from those proposed in 2016. There are many detailed changes at the level of application and implementation, but the EA's basic concepts remain: ie

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[1] Which I refer to in this report as "the Issues Paper". Unless otherwise stated, all paragraph references and quoted extracts are from this paper.

[2] "Review of the Authority's TPM Options Paper", August 2015, "Review of the Electricity Authority's Second Issues Paper", July 2016 and "A response to Meridian's Submission to the TPM Consultation", September 2016"

1. *Beneficiary-pays*: allocating the costs of new transmission between users based on a calculation of benefits expected to be received;
2. *Fixing transmission charges*: as far as possible, predicating charges on forecast or historical usage rather than current usage.

I expressed my concerns around these basic concepts in my submission to the 2016 Issues Paper. These concerns remain.

However, there is some new and useful material in the Issues Paper, which I focus on in this paper. In particular:

- The development of 6 new pricing principle[3], drawn from a long discussion of the dynamics of workably competitive markets and relevant lessons and analogies for transmission; and
- A discussion around the efficiency of nodal prices, with reference to actual and hypothetical reforms to the design of the spot market that would improve this efficiency.

This change in emphasis by the EA reflects two new components of the "material changes in circumstances" that the EA must demonstrate to justify a review of the TPM guidelines. These new changes are:

- "The increasing range of technologies available to electricity consumers are fundamentally changing the way people engage with electricity markets."
- "New ambitious climate change Government objectives affect the demand for and use of the grid"

The EA rightly acknowledges that, under these changes, the role of the demand-side in the spot market becomes more important and substantial. It is appropriate that the TPM should reflect these spot market changes. But, unfortunately, as the pace of transition into this new world grows, the EA remains entrenched in positions it established almost at the outset of this TPM review.

[3] Issues Paper, para D.86

1.5 STRUCTURE OF THIS PAPER

The EA's new six pricing principles are:

a) "LMP is generally the best means of restricting the use of the grid to its capacity
b) each user should pay the cost of connecting it to the grid
c) the charges for access to transmission services from a transmission investment in the grid should recover the total cost of providing the transmission investment
d) subject to paragraph (e) below, charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment
e) charges for a transmission user should be similar to those for other competing users after adjusting for their size and location
f) any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable."

I have structured this paper around these principles, considering for each one:

- what it means and whether it is appropriate;
- how and whether the EA's proposals flow from the principle; and
- what alternative TPM options might better achieve the principle.

The exception is principle (b) which relates to connection charges, which I have not reviewed.

The EA also articulates a seventh principle:

> "you pay for what you get"

as a condition for ensuring durability of the TPM regime. I have similarly considered this additional principle.

Like the "material changes", the EA's principles have changed and evolved over the course of the TPM review, but despite this the fundamentals of the proposed TPM remain largely unchanged.

2 ROLE OF NODAL PRICES

"LMP is generally the best means of restricting the use of the grid to its capacity": EA's first pricing principle

2.1 INTRODUCTION

In the Issues Paper, the EA considers the design, outcomes and impacts of nodal pricing in considerably more detail than in previous papers, both qualitatively and (through its cost-benefit analysis) quantitatively. This is largely in response to stakeholder comments that the existing regional coincident peak demand (RCPD) charges are complementary to nodal prices and help to improve efficiency and reliability. The EA's position is that nodal prices are already efficient – as reflected in its principle quoted above – and so adding a further price component can only detract from efficiency.

In exploring this question, the Issues Paper presents[4] a possible approach to further improving the efficiency of nodal prices. In my view, this is a very useful and interesting idea, in that it sheds light on this efficiency question, provides some insights into what the most efficient nodal prices might look like and even (as explained in the next chapter) provides a possible basis for an alternative TPM that would share those characteristics.

2.2 ROLE OF NODAL PRICES

Nodal prices are determined in the spot market in accordance with the market design and processes set out in the Code. They are not defined or determined pursuant to the TPM and so are outside the scope of the TPM guidelines.

Nevertheless, the EA is right to consider them as part of its TPM development process, for several reasons. Firstly, they clearly represent spot transmission prices: or, at least nodal price *differences* do. A generator at node A serving a load at node B and in perfect energy balance pays the difference between the node B and the node A price. If generator and load had been at the same node, no such payment would have been made.

Secondly, generators and consumers respond to the aggregate price they face so, in terms of transmission, will respond to the sum of the nodal price difference *and* the (administered) transmission price from the TPM. Therefore, in considering behaviour – and hence economic efficiency – for a particular TPM design, one must take account of the nodal price differences; otherwise, one may inadvertently charge for transmission *twice*.

Thirdly, the spot transmission prices will generate revenue, just as the administered prices do. This is referred to as the Loss and Constraint Excess (LCE). Whilst this revenue is not received by Transpower, it nevertheless is a potential source of funding for transmission and, somewhere and somehow, directly or indirectly, will reduce the revenue that transmission prices need to raise.

[4] para E.85

2.3 WHAT IS "LMP"?

LMP (locational marginal price) is the clearing price, at a node, of the dispatch-based auction: ie the nodal price. So it is not, in the context that the EA is using it, an idealized economic concept[5], but a practical outworking of the design of this auction and the behaviour of those participating in it. So the truth of the assertion in the EA's pricing principle is clearly contingent on these factors.

As the Issues Paper describes, substantial changes are currently taking place in both these aspects:

- The scheduled implementation of *real-time pricing* (RTP) in the spot market, which will generate nodal scarcity prices when the auction fails to clear; presently, only regional scarcity prices are generated;
- Greater penetration of *variable renewable generation* (VRG), to achieve grid decarbonization, will lead to more volatile dispatch and price outcomes;
- In response to this greater volatility, and enabled by cheap communications and control technologies, the quantity of *demand response* (DR) is likely to increase substantially: this DR could either be *dispatched* (participating in the auction and helping to set the price) or *non-dispatched* (responding autonomously to the nodal prices calculated in the auction).

In summary, LMP characteristics are likely to change substantially over the medium term due to the factors listed above and potentially other factors not yet identified. Currently, with no nodal scarcity pricing and very limit demand-side participation, it is unlikely that nodal prices live up to the theoretical ideal stated in the EA's principle. Possibly that might be achieved, or be closer to being achieved, in the future. But an effective TPM must reflect the practical realities of today's market.

2.4 STATIC EFFICIENCY

What does the EA mean by "best" in this pricing principle? Clearly, in the context of the discussion preceding it in the Issues Paper, the EA means "economically efficient". But is it referring to:

- *Static efficiency*: meaning lowest operational cost, given existing assets; or
- *Dynamic efficiency*: meaning lowest total cost of operation *and* future investment?

Static efficiency is considered below and then dynamic efficiency in the next section.

Static efficiency relates to the deployment and operation of *existing* assets: generation assets, such as power stations; consumer assets such as electrical appliances; and transmission assets. We can take grid capacity to be largely fixed and inflexible in this time scale, so the *supply side* of the transmission market is fixed and inelastic. Static efficiency means this fixed capacity being assigned to its most valuable use.

If auction participation is deep and competitive, it is reasonable to assume a high level of static efficiency. It is not necessary for *everyone* to participate; many users may be price takers, happy to pay

[5] or possibly it *is*. It is not entirely clear what is intended by the EA. But I will assume not.

for the transmission whatever its price. But we are very far from a deep market currently, with very limited participation on the load side.

This is particularly problematic when the auction does not clear: ie where the total demand from *non*-participants exceeds the transmission capacity. In this case two things happen:

- *scarcity pricing*: the nodal price will be set administratively to a scarcity price;
- *load curtailment*: there will be some load curtailment to balance transmission supply and demand.

Load curtailment is *highly in*efficient, for two reasons. Firstly, it is fairly indiscriminate: high-value load is curtailed along with low-value load. Ideally, the low-value load would participate in the auction (directly or indirectly) and have voluntarily *self*-curtailed, thus avoiding the need for the high-value load to be curtailed administratively. So greater auction participation would have successfully sifted the low-value load from the high-value. In its absence, crude administrative curtailment cannot do this.

Secondly, load curtailment it will generally occur unexpectedly, meaning that the consumer cannot prepare for it. In contrast, a consumer participating in the auction would have prepared to self-curtail and would have been able to do so at much lower cost.

In short, the level of load curtailment – or the flipside of this, the level of reliability – is a key factor in how efficient nodal prices are in a static sense. So, would raw nodal prices (ie with the existing RCPD charge removed) lead to reduced reliability and so *poorer* efficiency?

The EA has not satisfactorily explored or addressed this question at anything deeper than a cursory and theoretical level. It would be a bold step to carry out a real-life experiment by removing the existing RCPD charge and seeing what happens. However, the EA is proposing to permit Transpower to apply a transitional 5-year charge to manage this reliability risk, discussed further below in section 2.8.

In summary, the proposition that nodal prices best promote static efficiency may well be true at some point in the future, with anticipated changes in auction rules and participation, but it is unlikely to be true currently.

2.5 Dynamic Efficiency

Dynamic efficiency is a much more difficult objective, because it involves decisions on long-term investments. On the transmission *demand* side (ie generation and load users), this means decisions on the design, size and location of power stations, factories, appliances and so on. For nodal prices differences (on their own) to drive efficient decisions, they must somehow reflect the long-run cost of maintaining and expanding transmission capacity.

Nodal prices are determined by the intersection of supply and demand (for transmission) in the dispatch auction. So, clearly, they will depend upon the level of transmission capacity; downward-sloping demand means the higher the supply of transmission capacity, the lower the nodal price differences. But the level of transmission capacity, in turn, depends upon Transpower's investment policies and decisions, and the regulations that drive these. There is no reason to suppose, *ex ante*, that the level of transmission capacity just happens to be *exactly* the right amount for the nodal price differences to equate to the long-run transmission cost. Indeed, the EA makes the comment that:

> "users may never see the full costs of their actions because [transmission] investment is usually triggered 'early', before nodal prices have risen to levels commensurate with signalling that additional investment would be beneficial" (para E.80)

Which I interpret to mean that, under current investment policies (and the Issues Paper refers specifically to the Grid Reliability Standards (GRS)), nodal prices will be below the level required to promote dynamic efficiency.

In summary, it is unlikely to be the case that nodal prices promote dynamic efficiency and so they are not "best" in that respect, whatever meaning the EA intended. To be clear, this is not to criticize the NZ spot market design, which is rightly considered a "gold standard" design. It just reflects the fact that it is not just the spot market, but also transmission investment policy, that determines spot prices.

2.6 Fixing Dynamic Efficiency of Nodal Prices

The EA acknowledges in the Issues Paper that, because of this current inefficiency in nodal prices, an additional peak transmission price may be necessary. However, it then makes an interesting suggestion[6] for an alternative approach which would (as I understand it) amend the dispatch auction rules to better reflect transmission investment policy. With the two processes appropriately aligned, the resulting nodal prices *would* (according to the EA) be dynamically efficient.

This is an intriguing prospect. A major difficulty in designing a TPM is to define and determine dynamically efficient transmission prices. If a tweak to the spot market could deliver such prices, that would largely solve this difficulty. However, there are some questions that first need to be answered:

- Is the EA actually proposing to make this change to the spot market, or is this just a thought bubble: conceptually interesting but of no practical import to the TPM review?
- If this change is to be made, when will it be made and implemented and what should be done with the TPM in the interim?
- If it were to be introduced, what would be the practical impact on generators, retailers and consumers?

The EA needs to answer the first two questions because it then goes on to conclude[7] that, because nodal prices *could* be made dynamically efficient, there is therefore no need for a peak transmission price. The logic here is obviously flawed. Rather, unless and until this fix to nodal pricing is made, an administered transmission price will be needed – as a supplement to nodal prices - to ensure dynamic efficiency.

I consider the third question, on the practicalities of this concept, in the next section.

[6] Para E.85
[7] Para E.87

2.7 Risks and Hedging

Nodal prices can be volatile and unpredictable. The introduction of RTP is likely to increase this volatility, by introducing nodal scarcity pricing. The EA's idea discussed above is likely to increase volatility further.

Such volatility will inevitably impact on dynamic efficiency, because a necessary part of any user investment process is to forecast nodal prices. Even if these fixed nodal prices could in principle, signal the long-run costs of transmission, that is of no consequence if it is practically impossible for the investor to forecast these and so incorporate them into its investment decision.

But volatile nodal prices may have a much wider and more damaging impact. If consumers face these prices, this would inevitably create bill shock, confusion and concern. In fact, it would probably not be politically or practically feasible to expose consumers to such uncertainty.

The Issues Paper notes that consumers could find a retailer to hedge them against this risk[8], but that just begs the question of how a *retailer* could manage this risk. Indeed, a standalone retailer is much less capitalized than a typical consumer, relative to its spot price exposure, and so even less able to bear this risk.

A retailer can hedge its energy price risk by buying a hedge from a generator. But if the generator and retailer are located at different nodes, the retailer remains exposed to the price *difference* between the two nodes. A retailer can then buy a financial transmission right (FTR) to hedge nodal price differences, but only at nodes for which FTRs are available. It will still be left with the risk of price differences between its node and the nearest FTR node.

These unhedgeable risks are perhaps not a major issue currently for retailers. But the introduction of RTP will create new risks from nodal scarcity pricing; that is, scarcity pricing of *transmission* (as opposed to energy). The EA's idea, discussed above, would supercharge this risk. As a rule of thumb, long-run transmission costs are around 50% of total transmission cost. The LCE is currently only around 5-10% of total transmission cost. So achieving dynamic efficiency from nodal prices would involve increasing nodal price differences by a factor of 5 to 10, meaning retailer risks would rise by a similar factor. This would, at the very least, make standalone retailers unviable and so substantially reduce competition. It is not clear whether even a gentailer would be willing or able to incur this level of risk.

To manage this risk, hedges need to be made available to retailers. In practice, this means an extension of the existing FTR framework, whereby the LCE is used to back issued FTRs. These would need to be available for every node. Furthermore, the risks that the LCE would be insufficient, from time to time, to back these FTRs needs to be managed. Achieving this would obviously be a huge undertaking. As far as I am aware, the EA has no current plans to embark on such a program. Until it does, the concept of using nodal prices alone to achieve dynamic efficiency is just that: a concept, not a practical proposal.

[8] Para E.43

2.8 Transitional Arrangements

So, as it stands, the spot market is not even close to achieving the efficiency that the EA's principle articulates. Many years of development in market rules and participation would be needed to approach this ideal. Removing the RCPD price could *degrade* static efficiency if it leads to a worsening of reliability. Of course, reliability is managed over the long-term by grid investment. However, the response of load to a removal of the RCPD price could be quite rapid, so there could be worse reliability in the interim.

So, an interim price signal – or a more gradual phasing out of the RCPD price – could be justified, simply in terms of static efficiency and reliability, without evening considering the dynamic efficiency impacts. The EA has proposed a possible 5-year transition period, but it is unclear whether this would be long enough for either load-response to develop or for transmission investment to occur to meet peak requirements[9]. Indeed, Transpower would obviously do well to wait to see what load response might develop before rushing into new investment that could end up being stranded. So, it could in practice be much longer than 5 years before this is resolved. The TPM guidelines should allow for this, by giving Transpower discretion to design the transitional arrangements and to adapt them as appropriate to reflect spot market evolution.

2.9 Conclusions

The EA's principle that nodal pricing is "best" appears to relate to an aspirational ideal rather than an assessment of current price outcomes. The prospect of nodal prices being best in terms of static efficiency at some point in the future at least seems plausible, if uncertain. The idea that they could also be made to be dynamically efficient is conceptually interesting but practically infeasible. In neither instance does this justify the removal of the RCPD price on the grounds of improving efficiency.

Nevertheless, I think there is a possible variant of the EA's pricing principle that *can* be supported and is helpful in thinking about how to best promote efficiency: that nodal prices would *ideally* be the best way to promote transmission efficiency. That principle implies that the EA should continue to identify and develop ways to move closer to this goal. But the TPM design must reflect the world as it is, not as we would like it to be. The EA should acknowledge that nodal prices are not fully efficient and are not likely to be for the foreseeable future. It must develop a TPM that reflects and addresses that gap.

[9] In fact, growth in peak demand is expected even if the RCPD charge remains, but a removal of this charge would potentially accelerate this growth and bring forward the transmission investment needed to accommodate it

3 LONG-RUN PRICING

> *"the charges for access to transmission services from a transmission investment in the grid should recover the total cost of providing the transmission investment": the EA's third pricing principle*

3.1 INTRODUCTION

To promote dynamic efficiency, a transmission price is required that reflects the cost of maintaining and expanding transmission capacity. A user facing such a charge will factor it into its investment decision, trading off (through choice of location, size or design) the cost and value of the new asset against the cost of the transmission charges it will attract and, by implication, the cost of the transmission service that it uses.

Clearly, this assessment must be made at the time of the investment decision: once the decision is committed, it is too late to change. Ideally, the transmission charge reflects the future *extra* cost that the decision imposes on the transmission company. So, either the transmission company or the investor must be able to forecast that cost:

- If the *transmission company* makes the forecast, it must reflect that forecast in its transmission prices; this is the essence of a long-run costing methodology; or
- If the transmission company does *not* make the forecast, it simply charges the cost that the investor causes, as and when it occurs. This is the philosophy of the beneficiary-pays (BP) concept. The investor must then forecast what these future costs will be.

So, a fundamental question when designing a TPM is: who is best placed to predict future transmission costs? There are two aspects to this.

- *technical ability*: it is self-evident that the transmission company will be in a better position than a third-party to forecast transmission costs, because it has the technical knowledge and the market-wide information necessary, and so forecasting errors will be smaller.
- *risk appetite*: uncertainty around future transmission charges will add to the riskiness – and hence the cost of capital – of investments. If charges are locked in, based on the transmission company's forecasts, forecasting errors will effectively be spread across all transmission customers (through the residual charge) and create much lower investment risk

So, fundamentally, the long-run costing approach leads to lower risks. If a beneficiary-pays approach is to be adopted, it must demonstrate efficiency gains that more than offset that drawback.

3.2 LONG-RUN NODAL PRICING

The EA's idea of adjusting the dispatch process so that nodal prices better promote dynamic efficiency, was discussed in the previous chapter. A critical concern with this idea would be the degree of spot price volatility that it would create which, without hedges being available, would likely make energy retailing unviable. However, if this volatility could be removed, without also removing the efficient pricing signal, this could be an attractive option.

The volatility does nothing to improve investment efficiency, since it is the overall value of the investment over its life that is important for an investment decision, not the profit or loss in each half-hour. So, in practice, the investor would – under such a regime – just be attempting to forecast *average* nodal prices over the investment life. Which is, of course, what investors effectively do currently in relation to the existing nodal pricing regime.

So, to obtain an equivalent outcome, transmission prices could be *based* on that forecast average (dynamically efficient) nodal price over a reasonably investment horizon: eg 10 years. The forecasting would be done by Transpower.

The current spot market design[10] is left unchanged, so the investor will still face the current nodal prices in the spot market. Therefore, to avoid double charging, the transmission prices should actually be based on the *difference* between these two sets of nodal prices: again, averaged over 10 years or so. So, for example, a load at node X would pay a transmission price that is based on the expected difference between the dynamically-efficient price at node X and the statically-efficient price at node X, over the forecasting period.

Notwithstanding the underlying volatility of these nodal prices, the averaging will provide substantial stability. The prices could be recalculated by Transpower each year, with the 10-year averaging window updated accordingly, and so the prices would gradually change to reflect anticipated changing patterns of transmission flows and investment.

Leaving aside the overall practicality and tractability of forecasting these prices, this approach is an interesting *thought experiment* that can give some insights into what sort of pricing structures these ideas might imply and how these might be replicated or emulated in a simpler transmission pricing methodology.

The key insight is that, because scarcity prices, and other high nodal prices, will tend to occur around the times of peak load, these averaged prices will also be highest around peak demand and could be approximated by the sort of peak charging structure that we have currently. Indeed, that EA is asserting that these adjusted nodal prices will promote dynamic efficiency implies a *support* for peak charging, notwithstanding that elsewhere it argues that such structures are inefficient.

A second insight is that, because the scarcity prices are averaged over the 10-year (say) timescale, the average will be high at a node even where there is no *current* congestion. Rather, a high price would reflect occasional or anticipated congestion. The long-run price will signal to users the need to make investments to reduce or manage this congestion. This runs counter to the EA view that a node with no congestion at a particular point in time should not face a high transmission price at that time. Because that is a characteristic that only promotes static efficiency, not dynamic efficiency.

The final insight is that, because spot prices apply equally and oppositely to generation and load, these transmission prices would apply similarly[11]. Under this ideal there is no need to quarantine distributed

[10] Together with the scheduled implementation of RTP.

[11] Note that this is true only of this efficient transmission price component. The residual charge component would only apply to load, meaning that the *aggregate* transmission charge is asymmetric between generation and load.

and BTM generation from the efficient transmission price because, just by being deducted from the transmission customer's load, they automatically face the correct price.

3.3 Lumpiness of Transmission Investment

If nodal prices are, or can be made, dynamically efficient – either in dispatch or through a proxy transmission price – is there then a need for *additional* transmission prices, in particular the EA's proposed BP-based charges? The Issues Paper makes repeatedly the important point that, if you already have an efficient price, adding a further charge will simply *reduce* efficiency. So why does the EA not simply stick with these prices? Why pancake further prices on top?

A possible answer to these questions lies in a characteristic peculiar – if not unique – to transmission investment: its lumpiness. That is, due to its fundamental economics, transmission investment will occur at a scale which typically exceeds the immediate need for additional transmission capacity. To use the EA's hotel analogy, it is as though hotels can only be economically built at a very large scale which dominates the local hotel demand. Worse, unlike a hotel, a transmission operator is not even permitted to ration[12] the use of capacity, but must make it all available, even if this means crashing the price to zero (or, in the hotel analogy, to short-run cost).

I would infer that this lumpiness is a particular concern of the EA's, and perhaps a reason why it has not followed its idea of dynamically-efficient spot pricing to its logical conclusion, instead continuing to rely on BP charging to address its dynamic inefficiency concerns. Because, in the Issues Paper, the EA illustrates these concerns by using examples where lumpiness is a dominant factor: that is, where a new generator or large load prompts immediate transmission investment[13].

The EA's examples are designed to illustrate the inadequacy of nodal pricing in promoting dynamic efficiency. Here is one example: a new generator locates in an area of limited transmission capacity and so would, in the absence of new investment, face low local nodal prices as a result of the resulting export congestion. These low prices would be sufficient to deter it from locating there. However, because the generator can be confident (in the EA's example) that new transmission investment will be prompted, and this will be sized large enough to remove this congestion, it will never actually *face* these low prices. So – unless it is specifically charged for this new transmission – it can ignore this cost impact in its investment decision, leading to an inefficient outcome.

This story makes several assumptions, which are worth examining:

- That the new generation *will* prompt new transmission investment;
- That the transmission investment *will* be large enough to remove any prospect of congestion: not just immediately but for all, or much, of the life of the generating plant; and
- That the generator, in making its investment decision, *can confidently predict* the above two outcomes.

[12] even where such rationing would be operationally straightforward, such as on the HVDC
[13] For example, the case study on P11 and references in paras 4.110, 4.123, B.108 and D.54

Grid investment policies do not require that Transpower remove any and all congestion from the grid. It will only do so if (a) it is assessed as economic to do so in terms of the net benefit to the market as a whole or (b) it is necessary to maintain the GRS. These two investment drivers are considered in turn below.

Economic Investments

On the economics, the lumpiness of transmission is a double-edged sword:

- *If* the transmission investment *actually occurs*, it is liable to be sufficiently large to remove the generator's congestion concerns; but
- its larger size and higher cost make it less likely to be economic and so *less likely to occur*.

For example, suppose that the economic transmission "lump" is 200MW. It would likely be economic to invest to remove 200MW of congestion, and perhaps even 100MW of congestion (allowing for future growth), but not to remove just 20MW of congestion[14].

The EA is envisaging a situation of a large new generator creating some nearby congestion: so, say a 200MW generator creates 200MW of nearby congestion, and so investment in a new 200MW transmission lump to remove this congestion is economic. But consider instead a smaller generator or, alternatively a more remote (from the generator) location for the congestion. In this case, perhaps only 20MW of congestion is created, so there is no new transmission investment and the new generator bears the new congestion price, which it *should* therefore have factored into its investment decision.

Reliability Investments

Now consider the second driver for transmission investment; the GRS. In applying the GRS, it is important to consider whether the new generator is *firm*[15] or not. If it *is* firm, and also is needed to ensure reliable supply of peak demand, the GRS would mandate that Transpower invest to remove any export congestion. So this would give the generator some confidence that such congestion will be removed.

However, in practice, much future investment is likely to be variable renewable generation (VRG) which is not firm, in that it makes limited (wind) or no (solar) contribution to peak demand. For such generation, Transpower would probably *not* be required to remove the congestion for reliability reasons. Furthermore, because such generation is often fairly small, investment might not be justified for economic reasons either, as discussed above.

In summary, lumpiness can cause nodal prices (even dynamically-efficient ones) to be ineffective in situations where the arrival of a new generator prompts immediate transmission investment, and these are the examples that the EA focuses on. But there will be many other situations where transmission

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[14] This applies to the generation side, of course. On the load side, the GRS and the high attributed value of removing nearly all congestion substantially changes the economics.

[15] able to be relied on to be available to help supply peak demand

investment would not occur. To assess efficiency impacts, a systematic and comprehensive analysis must be undertaken. Cherry-picked examples of possible inefficiency present a distorted picture.

More generally, it is not clear that lumpiness will act to suppress the level of nodal prices differences overall, because it gives rise to two opposite effects that are liable to cancel out. On the one hand, a new lumpy investment will remove congestion, possibly for a considerable period, and so will set spot transmission prices to zero[16]. So, this would suggest that lumpiness will generally act to suppress these spot prices. But, on the other hand, lumpiness makes an investment project more costly, meaning that Transpower will be prepared to tolerate a greater degree of congestion before new investment becomes economic. So, this acts to raise these spot prices.

In short, lumpiness causes lower prices at the front-end of the investment cycle but higher prices at the back-end. The overall impact of these two offsetting effects is unclear. Some detailed, quantitative analysis is needed to identify whether lumpiness is a critical flaw in the use of nodal pricing concepts as a framework for developing efficient transmission prices.

So, to answer the question posed at the start of this section, lumpiness *could* undermine the effectiveness of transmission pricing based on dynamically-efficient nodal prices, but only in certain situations where lumpiness is a dominant factor. This could be addressed by a targeted transmission price that is limited to these situations. This is considered further in section 3.8 below.

3.4 Beneficiary-Pays

The Issues Paper puts forward three reasons why the EA proposes to introduce BP charges:

- *To promote efficiency in user investment*: by correcting the lumpiness problems discussed above;
- *To promote equity and durability*: by being able to demonstrate to users that they are only paying for transmission assets that they obtain benefit from; and
- *To promote efficiency in transmission planning*: by improving user engagement in Transpower's investment consultations.

The first of these reasons is considered in this chapter, with the other two considered in later chapters.

In relation to this first objective, there are two critical flaws in a BP-based approach:

- It relies on a user being able to forecast the future BP charges it will face;
- The price signals created by the BP charges will anyway be substantially below the long-run cost.

The first flaw is discussed below and the second flaw in the following section.

Going back to our original question of who should be responsible for forecasting long-run prices, the EA proposal puts the onus clearly on the user. A BP charge is fundamentally backward-looking in that it is only determined and applied when the relevant transmission investment project is developed and

[16] or, close to zero. There will still be a price to reflect marginal losses.

approved. At that stage, it is too late for users to reconsider their investment decisions that led to the transmission investment being needed. In appraising an investment, users must therefore construct their *own* forward price, in the absence of a forward-looking transmission price. The EA acknowledges that the effectiveness of the BP charge relies on users being able to do this.

This forecasting task will be extremely difficult. Forecasts must be made at three levels:

- Future *transmission investments* likely to be undertaken by Transpower over the life of the user's investment;

- The *allocation of benefits* between users for this investment and the consequent allocation of BP charges; and

- The *portion of those BP charges* that the user will face, under the various investment options.

This is a lot to ask of a user. Since Transpower has much more expertise and information around transmission planning, one would expect it to be better able to make these forecasts. So a possible variant of the BP concept would be for Transpower to do this forecasting for them.

These forecasts could be just "for information purposes" with the BP-based charging otherwise remaining unchanged. Alternatively, the forecasts could be converted into a forward-looking transmission price that is charged directly to users. Similarly to the "long-run nodal price" proposal, the long run BP-price could simply be a forecast of average BP charges (over the next 10 years, say) expected to be faced by users – generators or loads – at each location.

3.5 Dilution of BP Prices

Even if the user *could* forecast future BP charges, there is a more fundamental problem: the price signal created does not reflect the transmission cost that the user's investment decision causes and so will not promote dynamic efficiency when factored into this decision. Rather, it will be much lower than the long-run transmission cost, due a *dilution* effect, which is explained below, using a simple example.

Consider an investor who is considering investing in a new 100MW generating plant to supply a similar-sized new load. There are two options for the location of the generator, denoted as region A and region B of the transmission network. The new load, however, must be located in region B. Dynamic efficiency requires that the investor selects the option with lowest overall cost: generation plus transmission.

Suppose that transmission capacity from A to B has an average cost of $100/kW for economically-sized expansion projects and that the new generation-load pair is assumed to prompt a 100MW transmission expansion, at the cost of $10m, if region A is chosen for the new generation. The investor will then face associated BP charges. If region B is chosen, there is no transmission investment and no BP charges.

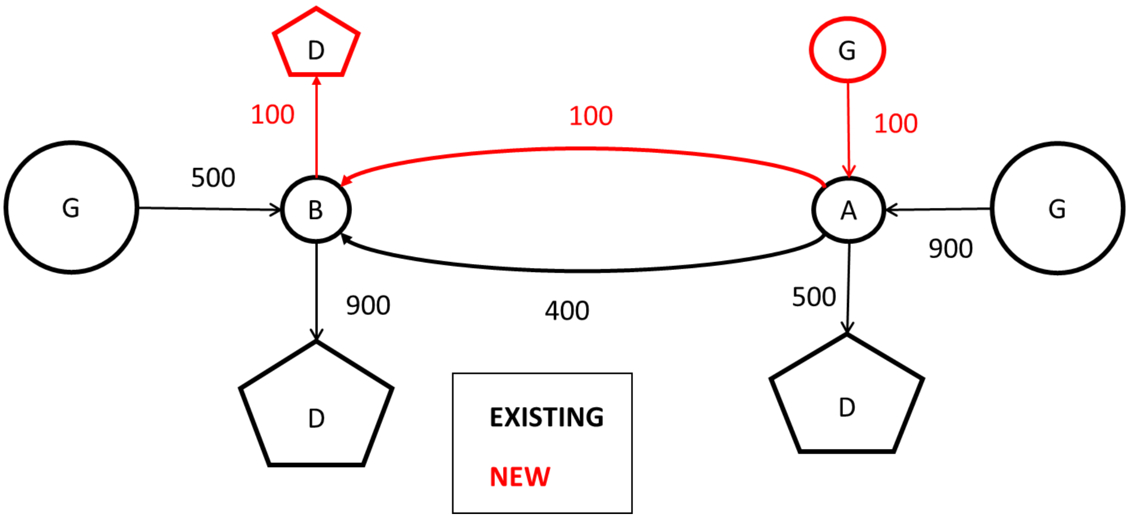

Figure 1: New generation-load pair locating across two transmission regions

The BP charge will be shared across *all* generation in region A and *all* load in region B, so the new generator's share will depend upon its market share in both these regions: in figure 1, the share is 10% in each case, so the new generator bears just 10% of the cost: ie $1m or $10/kW in terms of its generation-load capacity. So the new entrant bears just 10% of the additional transmission cost. This is clearly inadequate to promote dynamic efficiency.

In general, the dilution depends upon the size of the new investor compared to the size of the market which the new transmission serves. As discussed in section 3.3 the EA typically illustrates the effectiveness of the BP charge using examples in which the new transmission investment is local to the new user investment, meaning that the new investment is quite large relative to the associated market and so BP will be most effective. Again, the EA is missing a key issue with BP charging, because it is cherry-picking favourable examples rather than thinking of general or diverse situations.

The EA obliquely acknowledges the problem that BP charges will under-signal the long-run cost of transmission and so will not promote efficiency[17]. It argues that fixing this flaw is going to be too complicated, so this is the best it can do. But this conclusion is predicated on a consideration of a complex patch (a complicated variant of LMRC) for the problem, rather than a simpler TPM alternative (discussed in the next section). In any case, its BP methodology is itself pretty complicated. So, it seems to be preferring a complex TPM that does *not* promote efficiency over a (putatively) complex TPM that *does* promote it. This is incompatible with its statutory objective.

[17] Issues Paper pp 217-220

3.6 POSSIBLE BP VARIANTS

The above discussions suggest a couple of possible variants to BP-based charging that might help improve the efficiency of the signals it provides to investors, by reducing or removing this dilution effect:

1. Applying BP charges in relation to *all* assets rather than just future assets; and
2. Providing transmission *rebates* to those with negative benefits from the transmission investment, in addition to charging those with positive benefits.

These two options are considered in turn below.

Pancaking of Historical BP Charges

In the example given, there is *pre-existing* transmission capacity interconnecting the two regions. If the cost of these assets were also recovered through BP charges, this would add to the price signal that the new investor faces. The existing capacity is 400MW, compared to the new capacity of 100MW, so under this variant the BP charges would be around 5 times higher than before, or $50/kW. This is much closer to the long-run cost of transmission.

However, this variant has its own dilution problem. If the investor had opted instead to build its generator in region B, it would still face BP charges on its region B load for the historical assets[18]. If, say, the *generation:load* charging split was 50:50, this would amount to around $20/kW (50% of $40/kW). So, the *incremental* cost of choosing to locate the generator in region A rather than region B is just $30/kW ($50/kW minus $20/kW), compared to the long-run transmission cost of $100/kW.

BP-based Rebates

Providing *rebates* to those parties who receive *negative* benefit (ie detriment) from the transmission investment has two separate effects: it leads to the level of the BP charges being higher, and therefore closer to long-run transmission costs; and it removes the BP charge from a generator-load pair in the same location.

To see the scaling up effect, consider again the example above. The generation in region B and the load in region A will both be negatively impacted by the transmission investment and would therefore be entitled to rebates under this option. To fund these rebates, the charges to the beneficiaries would need to be higher.

Where the benefits arise from changes in nodal prices, the detriment to a generator will be broadly equal to the benefit to an equivalent load at the same location, or vice versa. So, if the new entrant decided to invest in new generation in region B, the BP-based charge on its load would be largely offset by the BP-based rebate to its generator.

Returning to figure 1, if the detriments are equal and opposite to the benefits, then there is a net payment on just 500MW in each region: eg in region A, 1000MW of generation pays a BP charge, but

[18] but not for the new asset, which would not be built in this scenario

500MW of load receives a rebate. If we assume, for simplicity, that the BP charging rate is the same in each region, then the $10m cost of the new transmission is shared across 1000MW, leading to a $10/kW rate in each region, meaning the new entrant pays a total of $20/kW: $10/kW on its generation in region A and a further $10/kW on its load in region B.

These two options can be combined. Levying the charge on new and existing transmission capacity must recover 5 times as much as before and so will lead to 5 times the charging rate. So the new entrant now faces a $100/kW which reflects the long-run transmission cost. So the dilution problem has been fixed.

3.7 Tilted Postage Stamp

Two possible transmission pricing approaches are discussed above which involve Transpower forecasting the outcomes of complex pricing methodologies: long-run nodal pricing and long-run BP charging.

The forecasting processes required in these options would be complex and potentially contentious. It is hard enough to forecast *actual* nodal prices; forecasting these *hypothetical* nodal prices would add a further level of complexity and opacity. Forecasting BP charges, similarly, adds a further layer of difficulty onto the BP charging concept, which already requires complex modelling to identify beneficiaries.

To avoid such complexity, it is often possible and appropriate to use a *heuristic* approach: a simpler method that, empirically, is expected to give similar pricing outcomes. Ideally, this approach would still fundamentally reflect the pattern of transmission flows and usage in the market, so that it would adapt appropriately if these were to change over time.

Nodal prices are generally higher in importing regions and lower in exporting regions, so the long-run nodal pricing approach would lead to prices that "tilt" upward from south to north, reflecting the generation direction of transmission flows and congestion. Similarly, since the allocation of benefits from transmission investment will reflect the *removal* of this congestion, the long-run BP prices will have a similar-style tilt. So, the heuristic method will involve tilting prices in the direction of transmission flows and can reasonably be called a Tilted Postage Stamp (TPS) to reflect the history of such concepts.

Reflecting its more complex antecedents – long-run nodal pricing and long-run BP charging - the TPS prices would also have the general characteristics of:

- Applying to peak load or output; and
- Applying equally and oppositely to load and generation in the same location

The TPS concept has been around a long time and, in my view, is not going to go away. This is because all plausible transmission pricing methodologies are likely to demonstrate these characteristics over the long term if appropriately designed. If there are two ways to get to the same destination – an easy way and a hard way – the easy way will always be preferable.

3.8 Deep Connection Charge

As noted above, the EA's concerns around dynamic efficiency seem to centre on a scenario of a new generator or load prompting investment in *shallow* transmission to remove the *local* congestion that it would create. It sees the need for a BP charge to address these particular circumstances.

But this "shallow investment" issue could instead be addressed by extending the existing connection charging regime to incorporate *deep* connection charges. Connection charges apply only to *dedicated assets*: those used *only* by the connecting user. A *deep* connection charge would extend this to network assets used only by a *few*, local users, of the sort envisaged in the EA's examples.

A deep connection charge would be similar to a BP charge in that the costs of the shallow asset would be shared between local users in proportion to the attributable benefits. However, unlike the BP charge (but similar to a connection charge), it is a one-off charge that is applied when a new user connects[19]. So, it is something of a hybrid between the BP charge and the connection charge.

Of course, this begs the question as to how to distinguish "deep" and "shallow" assets. We already have the concept of the core grid in the GRS, so perhaps this could be used. Alternatively, we have the set of key regional nodes that the current FTR regime applies to. So, perhaps shallow assets would be those assets that provide access to the nearest regional node.

This deep connection charge would be used in combination with a TPS regime or similar, improving efficiency in relation to shallow and deep investment, respectively.

3.9 Options assessed in the Issues Paper

The Issues Paper considers several alternative options and concludes that these are all inferior to the proposed TPM, for various reasons. Many of the assessed options are ideas that have previously been floated – and ultimately rejected – by the EA in earlier consultation papers. I would not disagree with the EA's conclusions on these.

However, two options are assessed that have some superficial similarities to the options that I have advanced above. Below I explain why either my options are substantively different to the assessed options or why I disagree with the EA's assessment.

Tilted Postage Stamp

The EA evaluates a model of the TPS which sounds like it would be similar to what I understand the TPS concept to be, except for this feature:

> "the charge is not related to customers' energy use and … the cost of new investment is recovered from all designated transmission customers in proportion to their existing transmission charges." (para E.127)

This is the antithesis of what I would understand the TPS concept to be, which is a charge *proportionate* to energy use and (largely) independent of *individual* new investment. It appears that the EA is trying to

[19] in this respect it is quite different to the "deeper connection charge" method that the BP has suggested in earlier consultation, although it might apply to similar assets.

remould the TPS concept in "its own image" of a BP-based methodology, albeit with a TPS-style starting point.

The EA needs to evaluate a TPS model where transmission prices reflect long-run transmission costs, as discussed above. This should be done using a cost-benefit analysis which is comparable with that used to evaluate its proposed TPM.

LRMC

The EA has asked a transmission pricing expert, William Hogan, to evaluate some version of LRMC-based charging. Although I do not refer to LRMC specifically, the underlying philosophy is similar to the long-run charging options I have discussed above: ie that the TPM should do the hard work of forecasting future transmission costs, not the user.

Leaving aside the criticisms that are *specific* to the particular variant being considered, Hogan makes the useful point that the attractions of LRMC rely on three underlying, but (for him) flawed, assumptions:

- *That because LRMC can be described, and appears tractable, on a radial network, it can be generalized to a meshed network*: but Hogan argues that loop flow effects are important and substantially increase complexity
- *That the LRMC function is relatively simple and well-behaved*: but Hogan argues that in practice it is complex and non-convex: eg due to the effects of investment lumpiness
- *That customers are myopic, in that they cannot predict future transmission prices and so have to have the forecasting done for them*: but Hogan argues that this is not true, particularly for large sophisticated customers

I do not agree with Hogan that these three assumptions are faulty, for reasons discussed below.

In response to the first point, I would agree that loop flow effects complicate everything, and this is true of any transmission pricing methodology you care to come up with: including a BP-based charge[20]. In any case, as I understand it, there are *not* major loop flow effects on the NZ network, and the major concerns that the EA has with the existing TPM are unrelated to loop flows: eg customers in Auckland not paying for the cost of investments that they benefit from. Furthermore, it is possible to remove loop flow effects using an appropriately designed TPM[21].

On the second point, the complexity of the LRMC depends upon how precisely one attempts to model it. Since the LRMC is based around forecasts, any attempts at precision will be spurious anyway. As discussed above, a simple, heuristic model – ignoring lumpiness say – is good enough.

[20] Notably, in his seminal paper on BP, Hogan uses, for illustration, exactly the simplifying assumption of a simple radial investment that he is now criticizing others for, albeit that he then generalizes this with complex mathematical algebra.
[21] the TPM used in the UK is an example of this approach

On the third point, the issue of customer myopia is discussed in section 3.1 above. I would turn this around. If even the transmission company is unable to come up with forward prices, for the reasons Hogan asserts, how on earth is the less-informed customer expected to manage?

In summary, whilst these criticisms might be applicable to some variants of an LRMC approach, they do not apply to the sort of simple long-run pricing methodologies (such as the TPS) that I am suggesting.

3.10 Conclusions

The BP approach can be effective and efficient in a limited number of situations where the entry of a new generator or large load is likely to prompt immediate and nearby “shallow” transmission investment. In arguing the case for BP charges, the Issues Paper always refers to such situations.

But the more general and typical situation, accounting for the majority of historical and future transmission costs, is “deep” investment on major transmission routes to accommodate general growth in transmission flows, being the aggregate effect of myriad investment decisions taken by smaller parties. BP does not promote efficiency in such decision making, due to problems of dilution and opacity. Dilution, because the pricing signal provided by BP charges in this situation is likely to be a fraction of the long-run transmission cost. Opacity, because it will be impossible for most parties to predict these future BP charges in any case.

There are several possible alternative TPM options that the EA can and should consider, which would overcome these difficulties and provide more efficient and effective prices.

4 Residual Recovery

"any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable": the EA's sixth pricing principle

4.1 Introduction

As discussed above, the primary objective of transmission prices is to promote – when added to nodal prices – dynamic efficiency. It is generally agreed that this level of transmission prices would be insufficient to recover the revenue requirements of a transmission company, based on receiving a regulated return on their asset base. In economic terms, economies of scale mean that the long-run marginal cost of transmission is less than the average cost. Of course, this is one of the key reasons why a transmission network is considered a natural monopoly. So, there will be a residual revenue requirement after the efficient prices have been levied and associated revenue received.

However, the residual charge that the EA proposes and requires is *not* related to this fundamental quality of transmission networks, but rather an outcome of which assets the BP charge applies to. If the charge applied to all assets, there would be zero residual[22]; if it applied to no assets, the residual would need to recover the entire revenue. The EA proposal is between these extremes, with some but not all assets being subject to the BP regime. Over time, as existing assets are renewed, replaced or removed, the BP revenue will grow progressively, and the residual revenue shrink accordingly.

4.2 Difference Between Long-Run Price and Residual price

There is a fundamental difference in the ideal user response to these two price components. We should be *indifferent* to how a user responds to a long-run price: whether its response is inelastic or elastic, it doesn't really matter because, either way, dynamic efficiency is promoted.

On the other hand, response to the residual price should be as low as possible because, by definition, any response will degrade dynamic efficiency. The extent to which it does this will depend upon user elasticity. Hence, the generally accepted *Ramsey principles* that, ideally, residual prices should be set on inelastic products: eg either on peak demand or on off-peak demand, depending on their relative elasticities.

4.3 Ramsey Efficiency of Existing TPM

The EA is critical of the existing RCPD charge, regarding this effectively as a residual charge which is poorly designed in a Ramsey sense and giving rise to substantial efficiency losses. However, these concerns are unjustified, exaggerated or unproven, for several reasons.

Firstly, the EA assumes that the entire RCPD charge is, in effect, a residual charge and so will degrade efficiency. This implies that the nodal price alone sends the appropriate long-run pricing signal. However, as discussed in section 2.5, even the EA is sceptical that this is the case.

[22] roughly speaking. There will be some differences in the amortisation profiles used in the BP charging and those used in revenue regulation, leading to relatively small residual amounts.

Secondly, the EA has not actually undertaken a Ramsey analysis: ie by identifying the elasticity of demand at different times so that a Ramsey-effective structure can be designed. In fact, the EA's CBA assumes that peak demand is highly inelastic[23] and so inefficiencies should be low, which the CBA analysis confirms. Furthermore, it appears that this CBA has not modelled distribution pricing which, since it forms a major part of the retail price that consumers respond to, will substantially affect elasticity. So, possibly, elasticity – and efficiency losses – are even lower than the estimates used in the CBA.

Finally, the current TPM guidelines give Transpower some flexibility to adjust the RCPD price structure to improve Ramsey efficiency, and Transpower has made use of this flexibility. Now, unfortunately, there is only one RCPD price, incorporating within the one charge an efficient price component and a residual component. The structural adjustment, whilst improving the efficiency of the latter might adversely affect the efficiency of the former. Ideally, the TPM guidelines would provide some flexibility for Transpower to develop separate structures for these two pricing components.

4.4 EA Proposed Approach

The EA proposes substantial changes to the residual charging structure, with a view to improving its Ramsey efficiency. There are three elements to this:

- Basing it on anytime maximum demand (AMD) rather than the current RCPD
- Lagging the incidence by 10 years: so the 2020 AMD, say, would not affect charges until 2030.
- Selectively applying the charge only to end-use that it considers to be inelastic

These elements are considered in turn below.

AMD

The proposal to move to an AMD pricing structure for the residual charge is surprising in the light of the EA's expressed concern around deployment of batteries to peak shave. Typically, the demand profiles of individual transmission customers can be very peaky, so peak-shaving is relatively easy compared to RCPD, where diversity – together with Transpower's averaging approach – make the profiles must flatter.

Lagging and Retrospectivity

The EA is, presumably, relying on the 10-year lag to substantially dampen such response to AMD-based charges. Of course time-discounting plays an important role here: any response made today will not be rewarded until 10 years in the future. The EA might also be relying on some scepticism and cynicism as to whether this charging structure is even *durable* for 10 years. A customer managing its AMD in 2020 will be disappointed ten years down the track, if the TPM it was responding to no longer exists.

In the first 10 years of the new TPM, the EA proposes to apply the residual charge, *retrospectively*, to historical (ie pre-2019) demand. This is surprising and inconsistent because, in response to concerns

[23] Issues Paper para 4.70

about charging retrospectivity (albeit in the context of BP charges rather than residual charges) the EA states:

> "We emphasise that our proposal does not involve retrospective charges – that is, changes to historical charges that customers have already paid. Our proposal only involves changing future charges." (para G.99)

But that is *not* the case when charges are based on a lagged measure of demand. For example, suppose that the 2022 residual charge is based on 2018 AMD. The customer has already paid – in 2018 – a charge for this consumption. Now a new charge is being levied, in 2022. This is retrospective in the sense that, had the customer known at the time that this new charge would be levied, it may have adjusted its use accordingly. Without a time machine, it cannot do this. And this is precisely what the EA intends.

Price Discrimination

Finally, the EA aims to reduce the elasticity of response by chopping out that component of end-use that is most elastic.

> "We propose to calculate a load customer's share of the residual charge based on demand 'grossed up' for injection by distributed generation or behind-the-meter generation as we think this better reflects customer size, and therefore ability and willingness to pay for transmission costs. It also provides better assurance that load customers will not be encouraged to invest in distributed generation or batteries just to avoid charges." (G.99)

Thus, the EA intends that Transpower would peer behind the meter: not just of its customers, but of the customers of its customers. It will then remove certain end-use appliances (ie distribution generation and batteries) from the residual charging calculation. It is clear from the rationale for this ("will not be encouraged to invest") that this is not about – or not just about – removing generation sources. It is more generally about removing end-use that is price elastic. This is a slippery slope: many investment options might be price elastic; indeed many may have greater price elasticity than a home battery, say.

This is not Ramsey pricing; this is *price discrimination*. This is picking on certain customers – or some portion of the end-use of certain customers – and saying: "I will charge you a different price for this". Price discrimination relies on the seller having some actual or inferred information about individual customers' willingness to pay. This is naturally hard to obtain, since consumers are not going to offer such information just so they can be charged a higher price. It is unclear how the EA anticipates that Transpower would obtain this information, and whether this would be legal or legitimate in terms of consumer privacy rights.

In summary, the EA's proposals for the residual charge rely on retrospectivity and price discrimination to minimize inefficient price response, rather than the generally accepted best practice of Ramsey pricing.

4.5 Alternative Options

The materiality of the residual charging issue is unclear, for several reasons. Firstly, there is no assessment of what the long-run cost of transmission is and, by implication, the size of the residual charge. The residual component in the proposed TPM is just an artefact of the BP approach and the choice of assets to which it applies: it could in principle be anything between 0% and 100% of transmission revenue[24].

Secondly, there is no proper analysis of user elasticity at different times and what this would imply for an optimal Ramsey charge versus the current charge or alternative structures. In fact, the assumptions used in the CBA seem to imply that the inefficiency from residual charges is likely to be quite low, at least for native load.

So an alternative option needs to be developed in two stages. Firstly, a long-run pricing regime needs to be established, so that the residual component can be identified by subtraction. Secondly, a Ramsey analysis needs to be undertaken. This would be best done by the party that is closest to the customer and best able to understand price responses: ie Transpower, not the EA. So the TPM guidelines should give substantial discretion to Transpower to develop Ramsey-efficient charging structures. As the current guidelines do.

Finally, those guidelines should explicitly prohibit retrospectivity and price discrimination. Whilst structures with those features – such as the EAs proposes – might putatively create some efficiency gains, these will be substantially outweighed by the attendant concerns around equity and durability. Indeed, as the EA points out

> "Perceptions of unfairness can detract from the durability, associated certainty and so the efficiency of the TPM." (para 2.25)

Durability is discussed further in the next chapter.

4.6 Conclusions

In contrast to the challenge of creating dynamically efficient pricing signals, the problem of residual charging is straightforward and generic. The same problem is faced by transmission owners and regulators around the world, because the fundamental economics of transmission mean that efficient prices alone will not recover the necessary revenue.

Rather than learn from overseas best-practice – and even best-practice in NZ[25] – the EA has developed its own unique ideas. These fail to apply the standard Ramsey principles, and instead rely on retrospectivity and price discrimination to minimise user response to residual charges.

[24] EA modelling, based on its proposed application of BP charging to certain historical assets, indicates that the residual charge will be around 70% of overall transmission costs initially, trending towards 50% over the long term. But, under the proposed TPM guidelines, Transpower has some discretion to change the selection of BP-charged historically assets, which could change the size of the residual charge

[25] ie the current RCPD charge design

5 DURABILITY

"you pay for what you get": EA's durability principle

5.1 INTRODUCTION

Regulatory Risk

The Issues Paper repeatedly emphasizes the importance of durability (the term appears over 60 times in the paper). The need for durability is used as a major argument both to terminate (ironically) the existing TPM regime and to replace it with a BP-based TPM design.

Durability is important, because a perceived lack of durability creates *regulatory risk*: uncertainty around whether or when the existing TPM regime will be overturned and what it will be replaced with. But, whilst it is important to avoid regulatory risk, there is more to this than just durability. Because there may be regulatory risk *intrinsic* to the TPM regime itself, no matter how durable it is; indeed, in this case durability just prolongs this risk. For example, TPM guidelines along the lines of "let the EA decide on the appropriate TPM" might be *notionally* durable but contains as much regulatory risk as a non-durable TPM. So, the TPM guidelines should seek to minimise regulatory risk *within* the regime as well as *around* the regime.

No Surprises

The EA argues that the major factor that promotes durability is perceived *equity* in pricing outcomes. It introduces a new principle to reflect this objective: "you pay for what you get". But, again, this is to focus on one aspect of durability, at the cost of neglecting other important factors. For me, the key to durability is "no surprises": ie to avoid ending up in a place we didn't expect to be and don't want to be. Two characteristics of a TPM regime are critical to avoiding this:

- *Transparency*: pricing outcomes should be reasonably predictable and explicable under a plausible set of future scenarios;
- *Adaptability*: the TPM should be able to be changed in a proportionate and coherent way to adapt to unforeseen new circumstances

If a TPM regime can avoid surprises – and *also* appear reasonably equitable – then it has a good chance of being durable. On the other hand, a regime which takes a narrow, prescriptive view of "equity"- and then applies this rigidly - becomes a hostage to fortune in the face of an uncertain future.

5.2 DURABILITY OF CURRENT TPM

The EA argues that the current TPM regime is not durable. A part of its argument for this is circular: the regime is clearly not durable, because it is being reviewed; it is being reviewed because it is not durable. But, more fundamentally, the EA argues that it is not durable because it is perceived as not being equitable, in terms of "you pay for what you get".

The current TPM uses a "postage stamp" approach of sharing all costs across all users. It is an approach which is common in other regulated markets, and also in non-regulated environments such as private clubs. It can be extremely durable: for example, in the postal service as its name suggests. If durability requires equity, then postage-stamping must be considered equitable in these contexts. Although I am not familiar with the history, I would infer that, at the time the TPM was established, postage stamping was widely considered to be equitable for transmission pricing too.

So, establishing a TPM that appears equitable *initially* is not sufficient to ensure durability. What is also needed is the adaptability to respond to unexpected changes in the market and to consequential changes in what approaches and outcomes are considered "equitable".

Returning to my "no surprises" objectives, the current TPM score strongly on transparency, in the sense that pricing outcomes are exactly as could have been predicted. It is also seen to have an adaptable pricing *structure*: and Transpower has indeed adapted this structure recently, in accordance with the TPM guidelines. Where it is not adaptable is in its pricing *level*, since the TPM guidelines do not permit Transpower to depart from the postage-stamping principle.

The EA notes that the current TPM regime has been under review (or under pressure to be reviewed) for virtually its entire existence. This comment is illuminating not so much for what it says about the current regime but about the process under which it was put in place and the fundamental difficulty of obtaining consensus support for a TPM. Unfortunately, transmission pricing is in large part a zero-sum game; whilst there are some efficiency benefits from a good design, it is primarily about how to carve up the transmission cake. It is almost inevitable in this context that there will be some disgruntled "losers" who will, of course, create pressure to replace the regime with one more favourable to them. This just emphasizes the importance of the current review finding a proposal that has widespread – albeit probably not unanimous – support.

5.3 Durability of Proposed Regime

The EA itself admits that the core of its proposed TPM – the BP charge applying to future investments - is *not* durable. It does not conform to its "you pay for what you get" expectations. The EA proposes to ameliorate this difficulty by including some historical assets in the BP regime. Perhaps the EA should reflect on what this says more fundamentally about its proposal.

In the second issues paper, the EA was guided by a principle of "service based pricing" and, in a submission on that paper, I argued that what the EA was proposing (which is fundamentally what it is still proposing) was not service-based but *asset*-based pricing. But what the transmission customer "gets" is a service, not an asset, so any TPM that is asset-based – rather than service based – is counter to the EA's "you pay for what you get" principle, and so undermines durability, even if it (putatively) adds to efficiency.

In proposing to include some – but not all – historical assets in the BP regime, the EA has opened up a new front in which winners and losers can do battle over the existing cake. Furthermore, by proposing to allow Transpower to re-open whatever set of assets the EA finally decides upon, the EA has allowed this battle to continue into the operation of the new regime.

For there to be some reasonable certainty and stability in this battleground, the EA would need to articulate some clear principles to guide the choice of assets. The EA has failed to do this. In fact, it has made things even worse by choosing to include only those recent[26] assets that show a positive net benefit. So a proxy battle will now be fought over the benefit modelling of each asset.

The EA argues that this selection criterion is needed to ensure that users do not face BP charges that exceed the benefits they receive. But this principle does not imply or require excluding particular assets from the BP regime. It could, instead, be ensured simply by capping the charges accordingly, rather than eliminating them entirely. If the capped charges then did not recover the full cost of the asset, the remainder would be recovered through the residual charge.

It is hard to escape the suspicion that there is some finessing of this choice of assets. That the selection has more to do with how the overall pricing outcome looks – and how this aligns with the "what you pay is what you get" objective – than any fundamental rationale. Indeed, as the EA admits, there is *no* fundamental rationale; or, rather, the fundamental rationale would conclude that *no* historical asset is included.

But while the *starting point* for prices can be massaged by careful selection of historical assets, its operational trajectory will be driven by Transpower's planning and investment processes, together with its modelling of benefit allocations. In an uncertain decarbonization future, it is unclear how this will play out. Indeed, the caps that the EA proposes to apply to year-on-year price changes implicitly acknowledge this uncertainty

Durability requires "no surprises" but it seems likely that there will be plenty in store under the proposed TPM.

5.4 Adaptability

The vehicle that allows the EA to reopen and review a TPM regime that has not adapted well to unexpected changes is the "material change in circumstances" clause in the Code. The TPM review has now being ongoing for long enough to there have been a *material change in those material changes*; in the latest Issues Paper, the EA has added two new elements[27] to the original list of three[28].

Furthermore, the two new elements are fundamentally forward-looking, in that their major impacts are still ahead of us. The EA – in its TPM proposals and its cost-benefit analysis of these – has endeavoured to anticipate what these impacts might be but, at this stage, this is largely guesswork. For example, a substantial part of the CBA relates to how the TPM will affect the deployment and use of network and home batteries. But the identified impacts are not expected to occur for a decade or more, and nobody can forecast with any confidence the cost or capabilities of batteries so far into the future.

These changes and uncertainties reinforce the importance of making a TPM regime adaptable if it is to be durable. But, paradoxically, the EA has endeavoured to *limit* adaptability in the calculation and

[26] since May 2004, except that the HVDC which is older is also included
[27] NZ government decarbonisation objectives and changing consumer engagement with the market due to new technology enablers
[28] governance, computing power and large-scale transmission investment

application of transmission charges. Both the residual charges and the BP charges are, as far as practical, to be *frozen* based on historical usage and forecast benefits, respectively, and not permitted to adapt as these factors change over time. At least, not permitted to adapt organically and automatically. The TPM guidelines provide opportunities for Transpower to reopen the benefits allocations, but it is unclear when, why and how Transpower might do this.

In the face of an uncertain *future* for technologies, regulations and behaviours, the EA has developed a TPM which faces the *past*.

5.5 Prescription in TPM Guidelines

It is notable that the proposed TPM guidelines are highly prescriptive compared to their predecessor[29]. Prescription creates potential for surprises in two ways. First of all, the greater complexity in the TPM implied by this prescription makes pricing outcomes less certain and transparent. Secondly, to the extent that this prescription removes discretion from Transpower, it makes the TPM less adaptable to future unexpected changes.

In a sense, despite their detail, the guidelines do actually provide for a fair degree of discretion, in that Transpower is able to opt for alternatives – or additions – to many of the prescribed methods. But that creates the opposite problem: of regulatory risk. Because the guidelines require that these alternatives are evaluated – by Transpower and then by the EA – against the EA's statutory objectives. To all intents and purposes, this means re-opening this TPM review each time Transpower opts to depart from the prescribed transmission method. In this sense, the new TPM regime could be durable in name but not in substance: pricing methods are liable to be under continual review by the EA.

This gives the worst of both worlds: a highly prescribed default method, combined with wide regulatory discretion on alternative methods. What is needed instead is an adaptive but stable middle ground, in which the TPM guidelines provide pricing principles, *within which* Transpower has discretion to design – and adapt as needed – the most appropriate pricing methods.

5.6 Conclusions

In conclusion, there are three elements that are critical to making a pricing regime durable.

Firstly, the pricing methodology needs to be intuitively reasonable; essentially, the EA's "what you pay is what you get" requirement. The EA's proposal does *not* have this fundamental characteristic, which is why it has had to finesse it by arbitrarily applying BP charges to historical assets, despite this being in opposition to the method's underlying rationale.

Secondly, the method must give a clear trajectory given the expected future, and this trajectory must remain intuitive. It is unclear whether the EA proposal will achieve this. As discussed in section 3.6, as existing assets are replaced with new assets subject to BP charging, it seems likely that the pancaked prices will better reflect long-run transmission costs. However, this depends on many factors: which

[29] the current guidelines are 3 pages long; the proposed guidelines require 18 pages.

assets are replaced when; what new assets are built; how the benefits are determined and allocated; and how the pancaking is done.

Thirdly, the methodology should have sufficient flexibility and adaptability to remain intuitively reasonable even when the future departs from what was expected. The EA proposal is poorly placed to do this at two levels. Firstly, the allocation of benefits – which is predicated on the *expected* future – is designed to be frozen, and so will not adapt when this expectation is not realised. Secondly, the methods are highly prescribed in the TPM guidelines and so are not easily adapted without, in effect, reopening the entire TPM.

So the proposed TPM guidelines possess none of these critical elements for durability. As is said of the court system, justice must be *seen* to be done. Similarly, for durability, transmission pricing must be *seen* to be equitable. But the complex, prescriptive and rigid TPM that the EA proposes cannot provide that basic and essential transparency.

6 TRANSMISSION PLANNING

"charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment": the EA's fourth pricing principle

6.1 INTRODUCTION

Efficiency of the transmission planning process is not usually an objective of transmission pricing, simply because those who make the transmission investment decisions (the transmission company and its regulator) do not face these prices and do not take them into account in the decision making. Of course, if transmission pricing is inefficient, this will distort the demand for transmission, which will *indirectly* lead to inefficient transmission investment. But that is simply one facet of the usual objective of pricing efficiency. And, whilst the EA raises this general concern, it also emphasises its more specific concern that the planning process itself – and the role of users within it – is inefficient and ineffective under the current TPM and would be improved in the proposed TPM.

My submission to the EA's second issues paper focused on the mechanics of this; how BP charging might, firstly, improve the level of user engagement in the planning process and, secondly, in so doing allow Transpower to glean additional useful information that would help it to make better investment decisions. My analysis concluded that:

- Engagement would *not* increase, because users are most likely to engage where the decision affects them, but beneficiary pays is deliberately designed to *reduce* impacts on users, by aligning new charges with new benefits;
- That any user impacted by the decision is conflicted from providing accurate and impartial information to the process and Transpower will discount the validity of the information accordingly.

The proposed TPM has not fundamentally changed (at least in relation to BP charging) since the last issues paper and my conclusions remain valid.

Rather than go over old ground, in this submission I consider the overseas antecedents for this BP charging method and philosophy: specifically its application in US transmission planning. It appears to me that the EA has borrowed the US concept and transplanted it to a fundamentally different NZ context, where it is neither appropriate nor beneficial.

6.2 BENEFICIARY PAYS IN THE UNITED STATES

The idea that beneficiary-pays based allocation of the cost of new transmission investment can improve the effectiveness and efficiency of transmission planning is well established in the US, to the extent that FERC has mandated beneficiary-pays for specifically this purpose. The Issues Paper argues that this lends support to its use in NZ. The EA has also obtained expert advice and submissions from a US expert – William Hogan – who has been influential in this policy development.

But what the EA seems to have missed is that there is a fundamental difference between the US context and approach and the NZ situation. The FERC order relates to allocation of investment costs between transmission *companies ("transcos")*, not between transmission *customers*. This is particularly relevant for the US context, where for historical and governance[30] reasons, there are numerous transmission companies, whose networks together make up the interconnected transmission systems.

Historically, each transco (or the integrated utility it forms a part of) would set tariffs to recover its investment costs entirely from its own customer base. For inter-zonal or inter-regional investments, from which much of the benefits flowed to the customers of *other* transcos, this led to the sorts of issues that the EA is concerned with: benefits not being aligned with allocated costs. At worst, where this meant that the cost to a transco's customers actually exceeded the benefits to them (because so much of the benefit was flowing outside their area), the transco might decide – or might even be mandated – not to proceed with the investment, despite its economic efficiency. The FERC ruling addresses this issue by requiring the costs of such an investment to be shared between the various benefiting transcos, and so between their respective customer bases, in accordance with the distribution of benefits.

This issue has no parallel in NZ, because there is only one transmission company. The TPM defines and determines how transmission costs are allocated between customers in different regions of the network. There is no sense in which, without the introduction of a BP charge, customers in a region of NZ would be responsible for fully funding the transmission assets that happen to be located in that region. So, there is no corresponding imperative to introduce BP based charges.

6.3 Practicalities of BP allocation between companies

Nevertheless, the US experience appears to demonstrate that BP charging is at least feasible. But this is again to conflate companies and customers when considering BP practicalities. The EA has overlooked fundamental and important differences between the two categories:

- For transmission investment, transcos are the decision makers, customers are just stakeholders. The latter might *influence* the investment decision, but it is the transco that makes it or, at least, has the power to veto it.
- Transcos are (in regulatory terms anyway) eternal and everlasting. There are no transco exits or entries, so the issue of how to re-allocate, retrospectively, BP charges to later entrants does not arise.
- Transcos are not users: they do not receive or respond to transmission prices; so the issue of pricing efficiency does not arise.
- Transcos regulatory regimes are based on recovering a portfolio of fixed, historical asset costs through variable prices; so freezing BP charges, to look like fixed asset costs, is a convenient approach.

[30] ie because the US is a federation of states

Furthermore, there have been some significant practical difficulties and disputes around what methods should be used for estimating benefits. It is probably not something that the FERC would have chosen to impose if there had been a simpler alternative. But, in the NZ context, there are many such alternatives.

Australia – which like the US has multiple transcos across its interconnected system – is currently facing similar issues to those seen in the US. In advising Australian clients, I have suggested a BP-based approach as a possible way to address these issues. So, I am certainly not inimical to BP approaches applied in the appropriate context. But I do not believe that they are sensible, practical or efficient for NZ.

6.4 Transmission Pricing in the US

For the US experience to be a relevant reason to consider BP charging in the NZ context, it would be helpful to see evidence of at least some US transcos applying BP methods to transmission *pricing*: ie to allocating investment costs between its customers. Given the US utilities and regulators have already worked on the practicalities of applying BP at the company level, it would be logical to extend this approach to the customer level; if, as the EA asserts, it is a superior pricing method.

There are myriad transcos in the US and it is not possible to generalize about how transmission pricing is undertaken. However, as I understand it, conventional transmission pricing methods are typically employed, such as postage stamping and peak charging. If the EA is to use the US experience to support its TPM proposals, the onus is on it to explain how these BP charges flow through to transmission customers and to explain how this is similar to what it is proposing for transmission customers in NZ.

6.5 Urban Planning

The Issues Paper also raises an interesting hypothetical scenario of a local planning authority requiring that transmission (new and/or existing) is undergrounded. Under the current postage stamp TPM, the cost of this would be shared across NZ. The EA argues that this may well cause this planning decision to be inefficient, in the sense that the cost of the undergrounding exceeds its value to the local community. If the TPM was instead designed so that the full undergrounding cost fell on this community, efficiency would be encouraged – presuming, of course, that the planning authority reflects the community's preferences in its decision.

But this example is an illustration not of transmission planning but of local urban planning. It is a different category and demands a different analysis. The first thing to note is that there is likely to be a great deal of "postage stamping" around infrastructure funding, where this is directly or indirectly funded by the NZ government through taxation revenue. So, "inefficiencies" of this type are likely to be endemic. As with transmission planning, this potential distortion of incentives is generally addressed in infrastructure planning by carrying out a cost-benefit analysis, rather than relying on the (distorted) preferences of the local stakeholders.

In the undergrounding case, the "taxpayers" are electricity consumers across NZ, whose interests the EA is required to promote. So, the EA is correct in considering that it has a potential role to play in correcting – through the TPM – this potential anomaly.

But this need not be done through a BP mechanism. If, instead, transmission pricing were based on long-run transmission costs[31], the undergrounding requirement would lead to higher prices in the relevant area. Indeed, some overseas markets (eg the UK and Australia) already factor undergrounding costs into their transmission pricing methodologies. One could even envisage a simple, albeit coarse, modification to the existing postage stamping approach, whereby the additional costs of undergrounding are postage stamped across all transmission customers within undergrounding areas.

In summary, undergrounding is a special and limited case that does not justify BP charging. However, such planning rules and restrictions would, ideally, be reflected in a long-run pricing methodology.

6.6 Conclusions

The philosophy that the TPM should be designed with a view to improving the transmission planning process is an idiosyncratic position held by the EA that does not have much support in overseas markets. Whilst the US does employ BP methods, these are used for allocating the costs of investment between transmission companies, a usage that has no relevance to NZ. As far as I know, the US does not use BP methods in the context in which the EA is proposing to use them: allocation of costs between the customers of a transmission company.

The US context has shown BP charging to be complex and contentious, particularly in the choice of method and assumptions. But applying it to transmission pricing would raise new challenges which the US has not had to face: whether and how to apply BP charges to new customers who were not present or anticipated at the time that the investment decision was made. Charging new customers is an anachronistic anomaly under the EA philosophy, because those customers cannot possibly influence a historical decision. But *not* charging them creates discrimination between old and new customers that is unlikely to be justifiable or sustainable.

[31] through one of the alternative mechanisms discussed above

7 COMPETITION AND NON-DISCRIMINATION

"charges for a transmission user should be similar to those for other competing users after adjusting for their size and location": the EA's fifth pricing principle

7.1 INTRODUCTION

The EA fifth principle of non-discrimination, quoted above, is – like its other pricing principles - drawn from its analysis and analogies of workable competitive markets. It is also consistent with the EA's "what you pay is what you get" principle for durability.

Yet, despite this principle, the EA's proposed TPM is riddled with discrimination.

Two examples of such discrimination have already been discussed. Firstly, the appliance-level price discrimination employed in the design of the residual charge, whereby consumption that has an elastic response will be priced differently to that with an inelastic response.

Secondly, the arbitrary division of existing transmission assets into those whose costs are recovered through BP charges and those recovered through the residual charge. Admittedly, this will not cause customers in the same location to have different charges, but it means the adjustment to a customer in a different location will be arbitrary. As the EA notes, for workably competitive markets:

> "In particular, if customers are relatively indifferent to the age of the asset providing the service, then the charge for the service will be independent of the age of the asset providing the service." (para D.26)

But this is not the case for the proposed TPM.

This section considers a further source of discrimination under the proposed TPM: by size. It also considers the impact of pricing discrimination, opacity and volatility on competition between users.

7.2 DISCRIMINATION BY SIZE

The EA proposes that the BP charges are *frozen*, based on the forecast allocation of benefits at the time of the relevant investment. That allocation will be between those customers existing at that time and based on the forecast usage of those customers. This creates two potential sources of size-based discrimination.

Firstly, suppose two customers are the same size (ie have the same usage) at the time of the investment, but customer A's size is forecast to grow much faster than customer B's. On this basis, A will be allocated a larger portion of the forecast benefit – and hence face a larger BP charge – than customer B. But suppose also that this forecast is wrong, and the customers in fact grow at the same rate and remain the same size. Clearly, A's higher charge is now discriminatory.

Secondly, suppose now that a new customer C connects in the same location. It faces no BP charge, because it was not there at the time of the investment decision. Clearly, this is discriminatory. Now, the proposed TPM guidelines leave it to Transpower to sort this one out[32], but provide no guidance on how

[32] clause 42 of the proposed TPM guidelines

this should be done, although the guidelines do contain a general non-discrimination clause[33] which is discussed further below.

Analogous problems arise in relation to the residual charge which, again, is essentially frozen, although this time on the basis of historical rather than forecast consumption. Two customers that were historically the same size – and so allocated the same residual charge – will face discrimination if they then grow at different rates. At least in this case, there is some possible efficiency benefits from minimizing avoidance of this residual charge[34]. In practice, no overseas market adopts such an approach, and this is because of the implications for non-discrimination, equity and durability. As the EA puts it "you pay for what you get", which means *variable* charges.

7.3 Discrimination versus Efficiency

The EA argues that freezing the BP and residual charges is necessary in order to promote efficiency. The argument is that, if the charges were *not* fixed, but rather varied in proportion to size as a non-discriminatory arrangement would require, grid usage would be distorted by this variable recovery of historical or sunk costs. In this context, it is not clear how Transpower is intended to interpret the non-discrimination clause that the EA has included in the proposed guidelines:

> "avoid discriminating between designated transmission customers, except to the extent necessary to achieve the Authority's statutory objective." (clause 1(f))

Because, the EA has asserted that freezing charges – and the consequent discrimination – *is* necessary to achieve the statutory objective. So, despite this non-discrimination principle, the EA would logically hope and expect that Transpower would choose to discriminate: ie to rank efficiency above non-discrimination.

7.4 Contracts

In many workably competitive markets – particularly those with long-lived assets with high sunk costs – the efficiency vs non-discrimination dilemma is resolved through the use of long-term contracts. Where prices are locked in for the period of a contract, the price will reflect the contract's vintage: ie the point in time when a customer entered into the contract. So, prices between "old" and "new" customers will be different, but this is not discriminatory in the usual sense of the term.

The EA often seems to rely on the attributes of a contractual framework, even in the absence of contracts[35]. In a contractual world, charges can be fixed. But this does not, and cannot, occur in a tariff framework. Tariffs *must* be non-discriminatory. The EA's principle reflects this, but its proposed TPM does not.

[33] clause 1(f) of the proposed TPM guidelines
[34] if it is appropriately set, as discussed in section 4.5
[35] and, to be clear, the EA is nowhere proposing term contracts for transmission customers

7.5 Competition

Promoting competition is one of the three legs of the EA's statutory objective and yet the EA fails to demonstrate how its proposals will promote competition. Indeed, the only example provided in the Issues Paper is of gas pipelines competing with electricity transmission, which is in any case beyond the scope of the statutory objective anyway, which refers to competition *within* the electricity industry.

A discriminatory TPM will undermine competition: particularly where it discriminates between old and new users. For example, a generator that is subject to BP charges might find it hard to compete with a later entrant who avoids such charges.

A TPM that lacks transparency and stability also undermines competition, by making it more difficult for smaller, newer players to compete with larger, established users, for two reasons.

Firstly, a stable and transparent pricing methodology puts users on a level playing field in that no significant resource is required to understand and predict transmission prices and their impacts on assets and investments. On the other hand, if the TPM is unstable and opaque, significant resources *are* required and this will obviously favour both *large* players who can provide and fund this resource and *established* players who will have acquired the industry knowledge needed to interpret and apply this TPM.

Secondly, unstable and unpredictable transmission prices can to some extent be internally hedged through the development of a portfolio of generation and load. The particular allocation of BP charges between zone A and zone B, say, is less important to a company that has assets, and so exposure to these charges, in both zones. A small player – with a single plant or localised customer base – will not obtain these portfolio advantages. So, again, the TPM disadvantages smaller users and so diminishes competition.

Small new entrants are the lifeblood of a competitive market due to their ability to disrupt the incumbents. Under the proposed TPM, they could be substantially disadvantaged, possibly to the extent that they do not enter the market at all.

Nodal energy prices are also unstable and unpredictable, so are these similarly anti-competitive? Well, to some extent they are. Certainly, it is more difficult for small players to manage spot market volatility and this is why the market is dominated by larger players. But it does not follow that we should seek or accept corresponding volatility in transmission prices: for two key reasons.

Firstly, energy price volatility is an *outcome* of the competition that the spot market rules are designed to engender. Alternative market designs (eg regional pricing rather than nodal pricing) are possible which would lead to less volatility but at the expense of competition. But there is no analogous way in which the volatility inherent in the proposed TPM is an outcome of competition, is necessary to promote competition, or reflects the design of the competitive market.

Secondly, whilst volatile, the spot market design is reasonably transparent, in the sense it is straightforward to develop or obtain a numerical model that will give you the nodal price outcomes for specified inputs. The volatility and uncertainty arise from the *inputs*, not the design itself. On the contrary, the TPM is opaque because there is no certainty around what model will be employed to calculate prices. As discussed above, even if a model could be developed and described with some certainty, that is unlikely to be durable because it will struggle to adapt to changing circumstances. The spot market, of course, does this automatically.

In summary, the competition leg of the statutory objective implicitly requires that the EA develops a TPM that is non-discriminatory, transparent and stable. The proposed TPM has none of these characteristics and so is unlikely to achieve the competition leg of the statutory objective.

7.6 Conclusions

In its relentless pursuit of "efficiency" in transmission usage and investment, and its fixation on BP approaches, the EA has neglected some basic principles of transmission pricing: non-discrimination, transparency and stability. In doing so, it has developed TPM proposals that are inconsistent with the competitive leg of the statutory objective.

8 CONCLUSIONS

8.1 NODAL PRICING

The EA's principle that nodal pricing is "best" appears to relate to an aspirational ideal rather than an assessment of current price outcomes. So, a better principle would be that nodal prices would *ideally* be the best way to promote transmission efficiency. That principle means that the EA should continue to identify and develop ways to move closer to this goal.

The TPM design must reflect the world as it is, not as we would like it to be. The EA should acknowledge that nodal prices are *not* fully efficient and are not likely to be for the foreseeable future. It must develop a TPM that reflects that fact and addresses that gap. That means, at the very least, providing for effective and flexible transitional arrangements so that administered transmission prices can continue to fill the gap between the *ideal* and the *actual* nodal price outcomes.

8.2 LONG-RUN TRANSMISSION PRICING

BP charging does not promote efficiency in user investment decisions, due to problems of dilution and opacity. Dilution, because the pricing signals provided by BP charges in this situation are likely to be a fraction of the long-run transmission cost. Opacity, because it will be impossible for most parties to predict these future BP charges in any case.

Instead, the EA should draw on the implications of its "nodal prices are efficient" principle. Because if nodal prices *are* efficient – even if only in a conceptual and unrealizable framework – then efficient transmission prices should have similar characteristics, albeit with their volatility removed to make them useful signals for investment. Whilst modelling the nodal prices themselves would be complex, developing a heuristic method which gives similar outcomes should be possible. The "tilted postage stamp" is an example of this approach.

When the entry of a new generator or large load is likely to prompt immediate and nearby "shallow" transmission investment, even these idealised nodal prices might not be efficient, due to problems of "lumpiness". These situations could be dealt with through a regime of "deep connection charging", where one-off charges are levied on the new entrants, reflecting the cost of the shallow investment that they prompt.

8.3 RESIDUAL CHARGES

In contrast to the challenge of creating dynamically efficient pricing signals, the problem of residual charging is straightforward and generic. The same problem is faced by transmission owners and regulators around the world, because the fundamental economics of transmission mean that efficient prices alone will not recover the necessary revenue.

Rather than learn from overseas best-practice – and even best-practice in NZ – the EA has developed its own unique ideas. These fail to apply the standard Ramsey principles, and instead rely on retrospectivity and price discrimination to minimise user response to residual charges.

8.4 Durability

As is said of the court system, justice must be *seen* to be done. Similarly, for durability, transmission pricing must be *seen* to be reasonably and equitable. Three critical elements are needed for this; the TPM must:

- be intuitively reasonable; essentially, the EA's "what you pay is what you get" requirement;
- offer a clear trajectory given the expected future; and
- have sufficient flexibility and adaptability to remain intuitively reasonable even when the future departs from what was expected

But the EA's proposal has none of these elements. The BP regime is not intuitively reasonable because it only applies to future assets, whereas transmission services are provided by *all* assets. It does not provide a clear trajectory, because this depends upon unknowables such as when and where investment will occur and how and to whom the benefits from these investments will be attributed. It is not adaptable because the methods are highly prescriptive and create charges that are frozen in time and not permitted to adapt to unforeseen changes in transmission usage and flows.

The EA offers some fixes to mitigate these fundamental flaws. It proposes to include some historical assets in its BP regime. It places controls on year-on-year price changes. And it offers Transpower some discretion to re-open various frozen charges. But these compromises are *ad hoc*, inconsistent and arbitrary; simply papering over the cracks of an unsustainable methodology.

8.5 Transmission Planning

The EA has argued, and continues to argue, that an important benefit of BP charging is that it improves the effectiveness of transmission planning, by encouraging useful user engagement in the process. To my knowledge, the EA is alone in considering this a material factor in TPM design, and still fails to offer any quantitative evidence to support its position.

In the latest issues paper, the EA has described BP practices in the US and argues that these provide support for its position. But this is to misunderstand the US approach and context, which is to allocate costs between transmission *companies*, not *customers;* a process that has no relevance to NZ, with its single transmission company.

The US context has shown BP charging to be complex and contentious, particularly in the choice of method and assumptions. But applying it to transmission pricing – as the EA proposes - would raise new challenges which the US has not had to face: whether and how to apply BP charges to new customers who were not present or anticipated at the time that the investment decision was made. The EA has not satisfactorily addressed this dilemma, either conceptually or practically.

8.6 Discrimination

In its relentless pursuit of "efficiency" in transmission usage and investment, and its fixation on BP approaches, the EA has neglected some basic principles of transmission pricing: non-discrimination, transparency and stability. In doing so, it has developed TPM proposals that are discriminatory, arbitrary and also inconsistent with the competitive leg of the statutory objective.

8.7 Conclusion

The Issues Paper contains some useful and interesting discussion around the role of nodal prices, the need for long-run price signalling, the importance of equity and non-discrimination, and the application of beneficiary-pays in the US. The problem for the EA is that none of these discussions, or their conclusions, point to the need for beneficiary-pays charges as the core of a new TPM. On the contrary, they show up its flaws and inconsistencies. It seems like the EA has long settled on this solution and now ignores its own arguments where they point to alternative approaches.

The EA should go back and read its own Issues Paper, and follow the ideas and insights contained therein to their logical conclusions: that if nodal prices are efficient, efficient transmission prices should have similar characteristics; that if the EA is forced, against its own principles, to have retrospective BP charging, then its own principles are flawed; that if charges are to be non-discriminatory and equitable, they must be variable, not fixed; and that if the US – as the home of beneficiary pays – has not incorporated BP into transmission pricing, perhaps it is not appropriate for NZ either.

Battery Analysis

Final Report

24 September 2019

Report to TrustPower Ltd.

John Culy Consulting

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DISCLAIMER

The information and opinions expressed in this report are believed to be accurate and complete at the time of writing.

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1 BATTERY INVESTMENT IN NZ

1.1 OVERVIEW

It appears that the Electricity Authority (EA) is concerned that the existing RCPD price signal could cause very significant inefficient investment in batteries once their cost falls sufficiently.

An examination of their Cost Benefit Analysis (CBA) shows:

- Their assumed reduction of peak period (top 800 hours or 1600 half hours) load under the Status Quo transmission pricing policy is derived from:
  - o Demand response (average 75MW over 2022-2050)
  - o The impact of investment in >3000MW of batteries within the distribution system to avoid the RCPD– resulting in around 1330 MW reduction in peak period demand.

A major component of the EA's CBA benefit relates to their proposal to remove the peak RCPD charge and hence to avoid inefficient investment in batteries in the Status Quo, and the impact of the increased peak demand on generation investment in their Proposed Transmission policy.

However, the EA analysis appears to substantially overestimate the investment in batteries in response to the current Regional Coincident Peak Demand (RCPD) price signal as a result of their highly simplified time zone modelling which:

- o Is not verified against actual or forecast half hourly demand profiles and does not adequately address the shifting of peaks as batteries are added (as evidenced by the average MW in their peak zone falling below the average in their shoulder zone), and does not account for the strongly declining marginal value in battery investments to avoid RCPD signals as the real peak demand over the top 50 hours is progressively flattened.

The analysis in this report is designed to address these substantial limitations in their modelling.

SUMMARY RESULTS

This analysis shows that the errors and inappropriate assumptions concerning battery investment and operation leads the EA to overstate the potential risk of excess "inefficient" battery investment in response to the RCPD price signal by a factor or around 6x.

Because the EA's analysis does not account for the impact of battery charging and discharging by hour changing the order of net demands within and between its very large load zones, it also substantially overestimates the impact of batteries on the shape of the load duration curve over the peak and shoulder. This overestimate has significant impacts on it's modelling of wholesale price formation and generation investment.

The more "fit for purpose" modelling of battery operation presented here shows that the current high RCPD price may provide a strong signal for battery investment, but this is not a significant efficiency issue for 10 years until battery costs fall significantly. Even if this efficiency issue grew over time, then it could be easily eliminated by phasing down the strength of the RCPD signal to a lower level over time as and when changes in technology and the market became more certain.

1.2 APPROACH USED IN THIS REPORT

This analysis is based on a detailed chronological modelling using 3 historical years of actual regional demand by half hour (2015 to 2018). Specifically, the analysis:

- Accounts for existing scheduling of ripple control etc to flatten the load curve;
- Models realistic hybrid operational strategies commonly used to manage peak load to a forecast load line, and to maximise energy arbitrage returns;
- Accounts for errors in forecasting load and limitations from battery storage; and
- Accounts for the impact of, and value derived from, incremental battery investment in each of the 4 regions currently defined.

This enables a marginal benefit curve to be derived as a function of the level of battery investment in each region which can be traded off against the annualised battery investment costs to determine a private "optimum[i]" level of battery investment under different levels of RCPD price level.

This "optimum" level of battery investment can be compared with the levels assumed by the EA.

1.3 COMPARISON WITH EA MODELLING

The comparison between the EA's modelling approach and this analysis are summarised in the following table.

TABLE 1: COMPARISON WITH EA MODELLING

Assumptions	EA's approach in Status Quo	This analysis
Battery Costs	Battery capital costs fall from \$770/kWh at 7% pa[ii]. This means battery capital costs fall to \$200/kWh by 2035 and \$70/kWh by 2050 (10% of 2017 value). Assumes 1hr battery storage.	Uses the EA assumption as a higher bound on cost declines, and a base assumption of 5%pa which is more consistent with recent work done by the ICCC, and Bloomberg New Energy Outlook 2018 estimates for a utility scale battery system out to 2030 (5%pa).
Battery system configuration and operation	Utility scale battery system operated in a coordinated fashion behind the GXP, on the assumption it benefits from generation at spot prices and 100% of RCPD avoidance and incurs the cost of charging at spot prices without distribution network costs. Excludes additional benefits from distribution investment savings and ancillary service provision.	Same as EA, noting that it is not clear who would have the incentive to own and operate such a system and there may be revenue recovery issues for distributors under Part 6 of the Code and potential distribution pricing issues relating to battery charging load avoiding distribution charges.
Time zones	Forecast of historical time zones: Peak: highest 800hours (9% of yr). Shoulder: next 1538hrs (18% of yr) Off peak: last 6373hrs (73% of yr)	Full chronological modelling by half hour based on 3 historical years of actual net load and spot price data in the 4 transmission regions.
RCPD signal	EA assumes that the RCPD signal is equivalent to an average "energy" price recovery over all hours in the peak zone.	This assumes that batteries are used as much as possible to lower demands down to a target level below the previous top 50hr (0.6% of year) load line.
Battery strategy	Hybrid strategy - 6 months peak avoidance and 6 months price arbitrage.	Hybrid – 5-6 months peak avoidance and 7-6 months price arbitrage.
Peak avoidance strategy	4-7 cycles per day at 50% discharge, 0.64 uncertainty adjustment for 180 days a year.	Reduce load to target load line without creating new peak. See 1.4 below.
Energy Arbitrage	2 cycles per day at 80% discharge, 0.50 uncertainty adjustment.	Charge and discharge on basis of high and low-price triggers which reflect daily variation in spot prices. See 1.5 below.
Estimated impact on net load of hybrid strategy	Each 1 MW of 1hr battery is assumed to deliver a net 0.42 MW reduction in peak period demand and 0.26MW and 0.27MW increases in shoulder and off-peak demands. See Battery assumptions for grid use model.xlsm.	Impact on average coincident peak demand over the top 100 hh is derived as a result of chronological simulation of the hybrid strategy and resorting of net loads accounting for battery operation. Impact on average peak, shoulder and off-peak MW is also calculated as a result.
Investment Function	Arbitrary investment function which limits rate of investment once batteries become profitable for the first MW. See page 60 of CBA Technical Paper.	Investment in batteries to the point where the marginal value from the last MW equals the marginal capital cost. No cap or limit on rate of investment is necessary, as investment in batteries is automatically self-limiting due to the nature of the RCPD price signal.

1.4 PEAK AVOIDANCE STRATEGY

The peak avoidance strategy follows a target load line approach commonly used in NZ. This assumes the battery operator:

- has a forecast of the top 100th half hour load (from history) including the impact of any other historical peak load control;
- sets a new upper target load line above which it is desirable to discharge the battery to reduce the net peak; and
- sets a lower target load to the desired level of battery charging when demand is lower, to avoid creating a new peak which is greater than target load line.

The modelled battery charging and discharging respects the limits on battery storage capacity and assumes that total regional demand data is available for the trading period prior, and battery charging/discharge is based on an evolving forecast of regional demand a short period ahead with a 2% forecast error.

This is illustrated for a typical day which has a high risk of containing a top 100 half hour load.

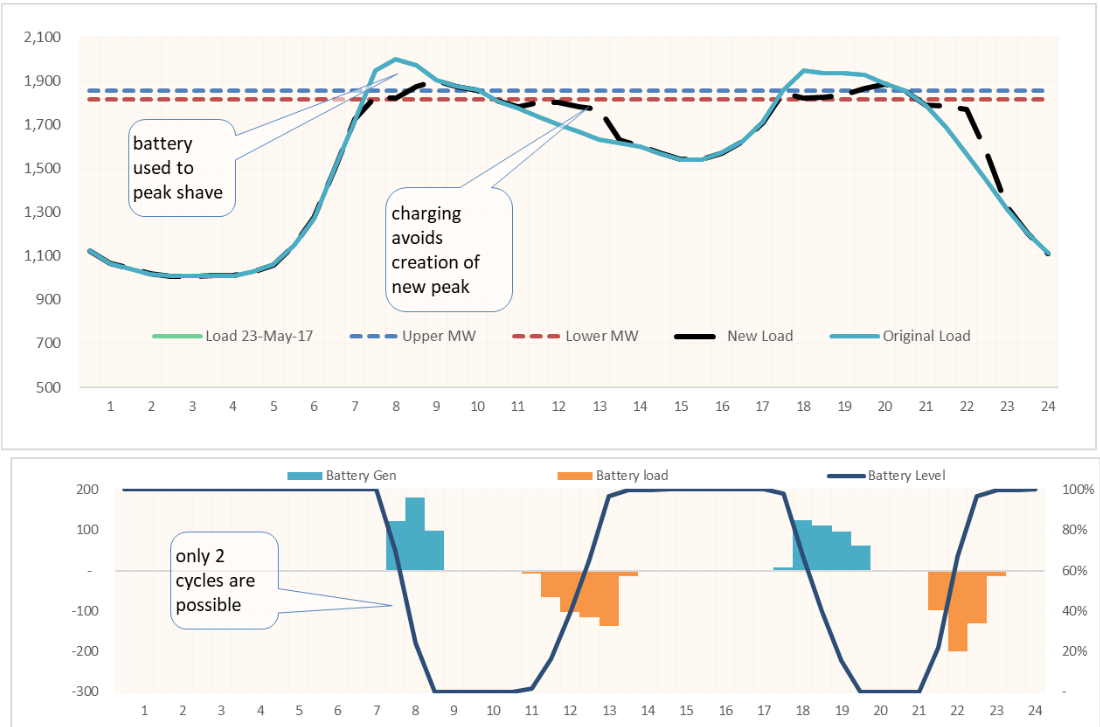

FIGURE 1: ILLUSTRATIVE BATTERY OPERATION IN PEAK AVOIDANCE MODE – TYPICAL DAY

The operation over a typical year (2016/17) by trading period is simulated to calculate the reduction in RCPD peak demand charges per MWh of total battery storage capacity (i.e. total $ saved in a year divided by MWh of battery capacity) for a range of different upper and lower trigger levels and battery storage capacity for each of a given level of MW investment in batteries.

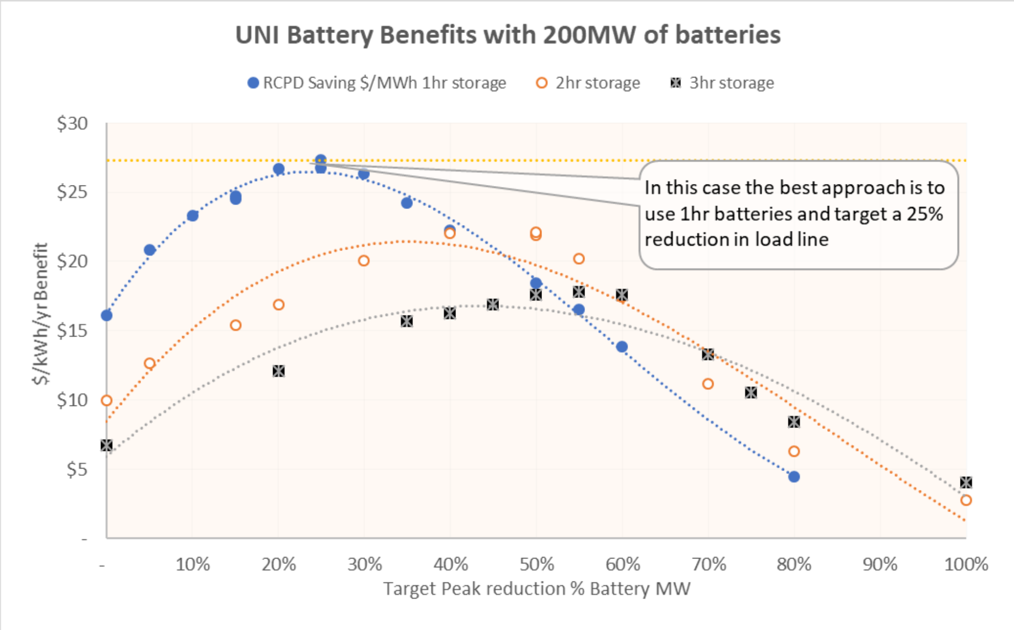

FIGURE 2: SIMULATED RESULTS FOR BATTERIES WITH DIFFERENT STORAGE AND TRIGGER LEVELS

This simulation enables the best combination of storage capacity and trigger levels to be determined for each battery MW size.

The simulated results for 200MW of batteries in the Upper North Island (UNI) are illustrated below. This shows that 200MW of 1-hour batteries can lower the load over the top 100hh by around 50MW.

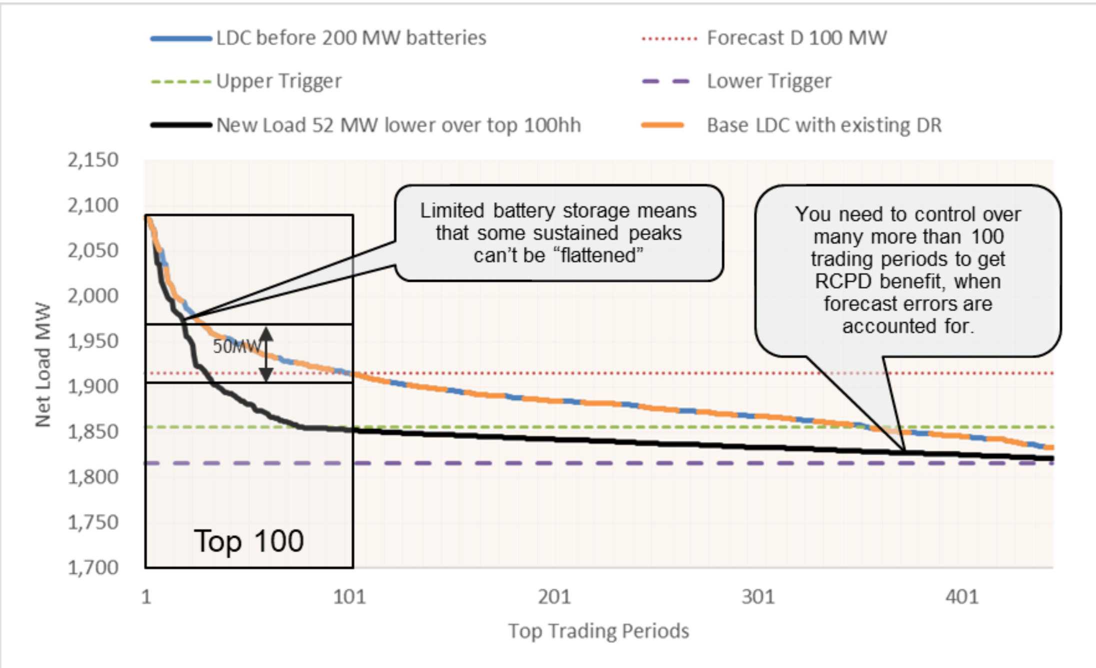

FIGURE 3: LOAD DURATION CURVE RESULTS FOR 200MW BATTERIES IN THE UNI

The impact of this strategy on the full load duration curve is illustrated below.

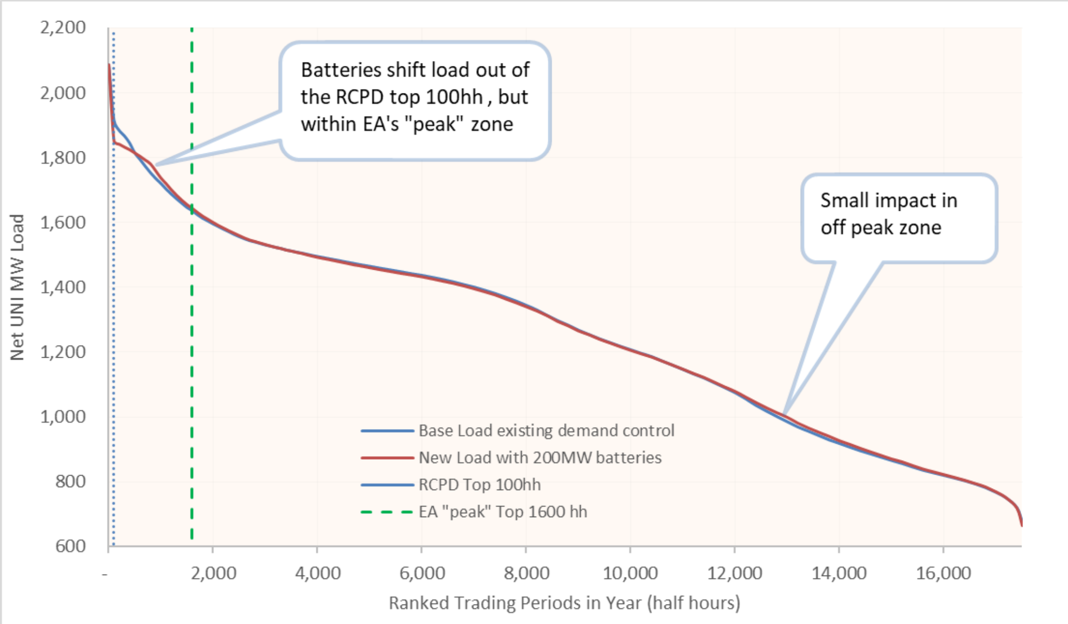

FIGURE 4: IMPACT OF 200MW BATTERIES ON FULL LOAD DURATION CURVE

1.5 PRICE ARBITRAGE STRATEGY

The price arbitrage strategy assumes the operator has a rolling average forecast for average energy prices over each coming day (depending on day type), and then derives an upper trigger price (approx. 10% higher than average) and a lower trigger price around 12% lower.

When spot prices during the day exceed the upper trigger price level, the batteries are discharged, and when spot prices fall below the lower trigger price level the batteries are charged. The actual battery charging and discharging accounts for the state of battery storage at the start of each trading period, and round-trip losses of 10%.

The best upper and lower trigger values can be found by simulation accounting for changes in price volatility over the day and year.

The arbitrage value is given by the gross energy margin = spot generation revenue – spot charging cost.

The price arbitrage value can be added to the RCPD value to get total value for a hybrid strategy as illustrated below.

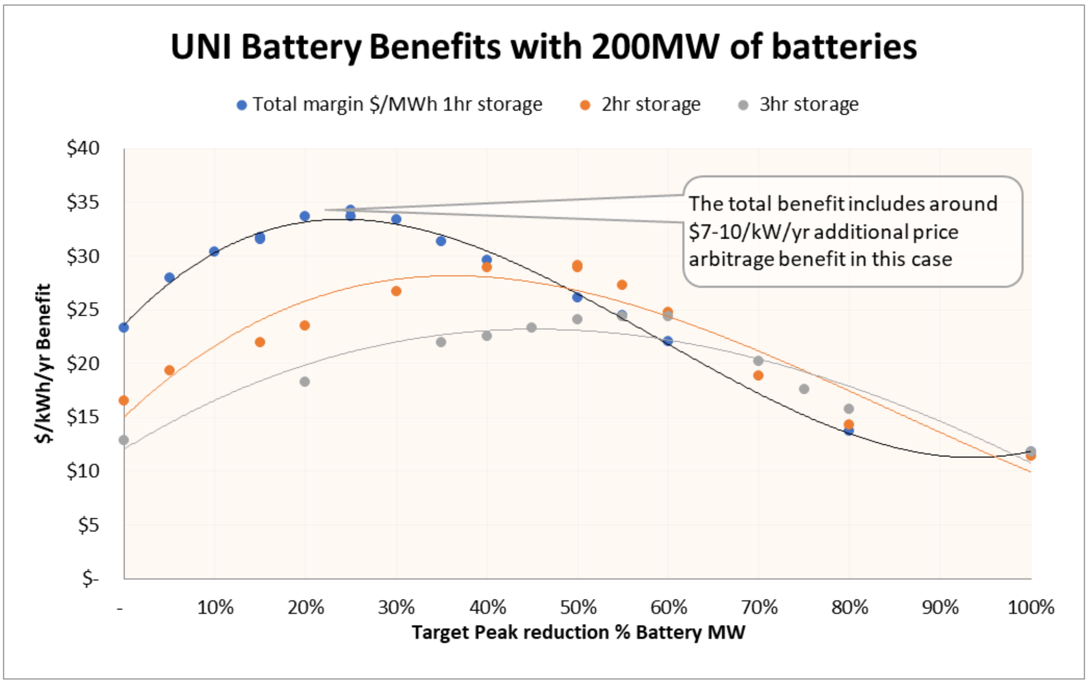

FIGURE 5: TOTAL MARGIN FROM A HYBRID STRATEGY IN THE UNI WITH 200MW OF BATTERIES.

This analysis is repeated for a range of battery investment levels and enables average and marginal benefit curves can be constructed. These are illustrated below.

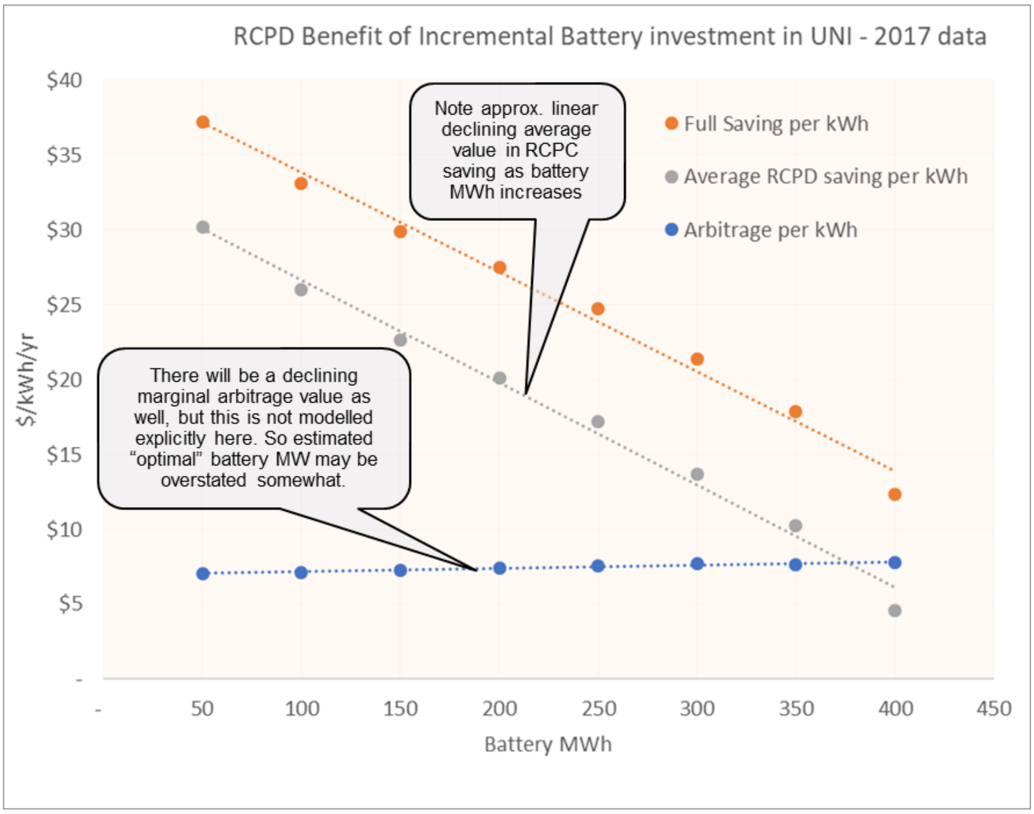

FIGURE 6: THE AVERAGE BATTERY INVESTMENT VALUE CURVE FOR UNI

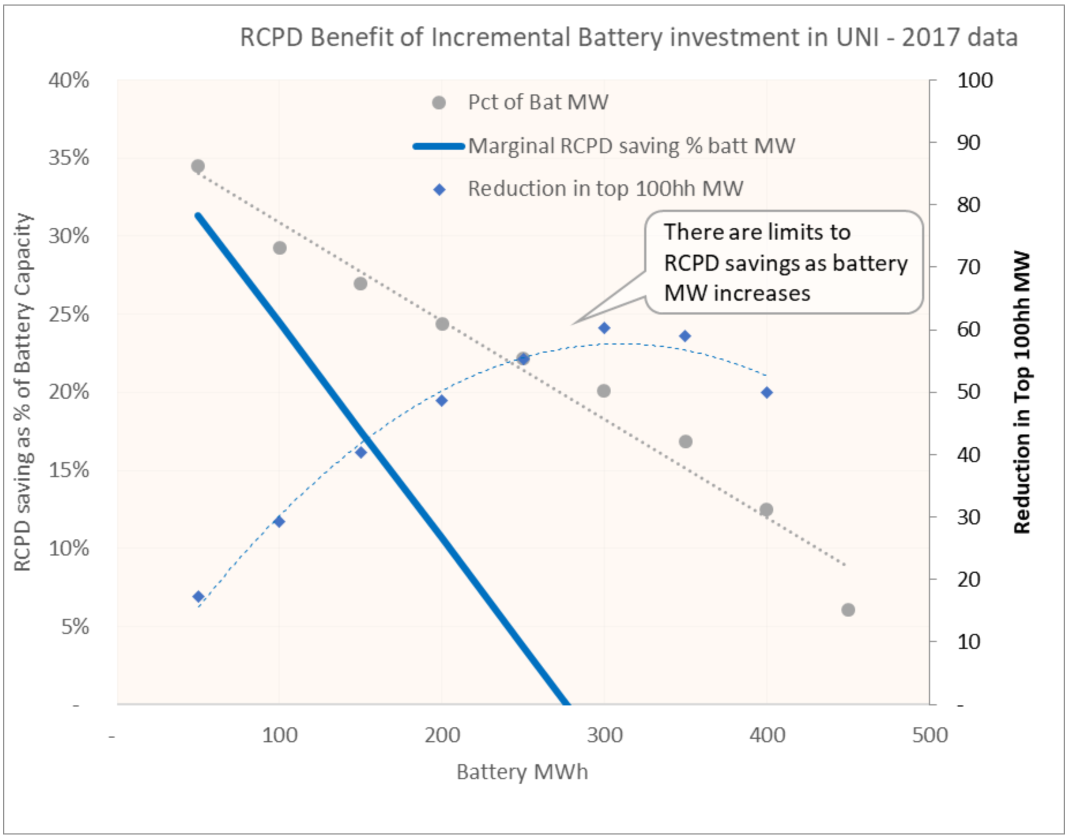

FIGURE 7: AVERAGE RCPD % SAVING AS FUNCTION OF BATTERY INVESTMENT

Note that the average RCPD savings are around 35% for low levels of battery investment, but then fall linearly as battery investment increases. The marginal RCPD saving falls at twice the average rate. This means that to total RCPD saving reaches a limit of around 280MW.

The same approach was be repeated for each of the 4 transmission regions with their own seasonal and diurnal load patterns and spot price volatilities.

1.6 INVESTMENT FUNCTION

The average battery investment curve can be used to estimate the marginal investment value, and this can be compared with the cost. The chart below shows the marginal RCPD value (blue) and compares with the marginal cost[iii] in 2035 with our assumed battery cost reduction and netting off an average price arbitrage value (green).

The optimal investment in batteries in 2035 is where the green and blue lines cross (a bit over 100MW).

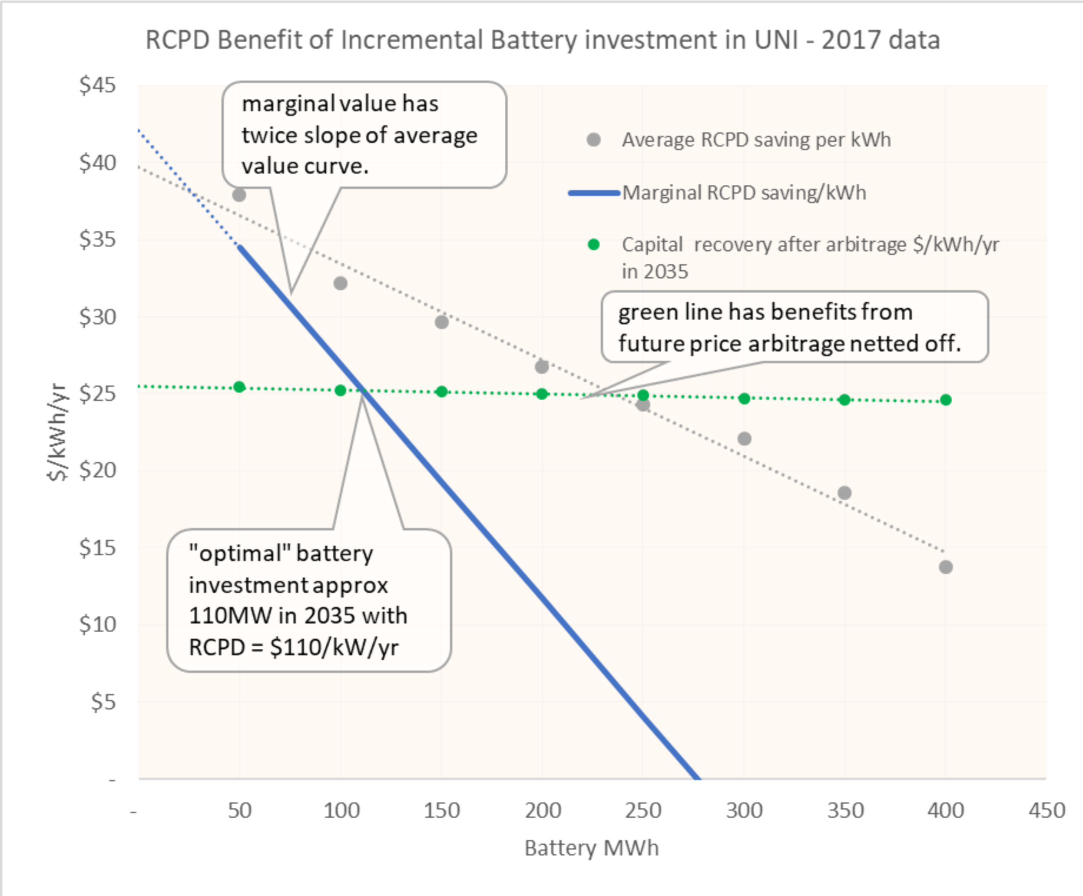

FIGURE 8: AVERAGE AND MARRGINAL BATTERY INVESTMENT BENEFIT CURVES

This analysis is repeated for each region in order to get the total investment in batteries in New Zealand. The results are sensitive to the shape of the existing net LDC, the RCPD price, the rate of fall in battery costs and the price arbitrage values.

The benefit curves assume that the RCPD price remains at $110/kW/yr. These curves would be lower if the RCPD price was lowered.

Note that while forecasting errors are partly accounted for, there are several other assumptions which make this estimate a conservatively high estimate[iv] of the level of battery investment expected if the current RCPD rate remains at around the current level.

1.7 RESULTS

The charts below show the results derived from this investment function assuming the current $110/kW/yr RCPD price and alternative battery cost decline rates. Figure 10 also shows that a phased reduction in the RCPD rate from $110/kW/yr down to $60/kW/yr by 2035 would eliminate any early investment in batteries prior to 2035.

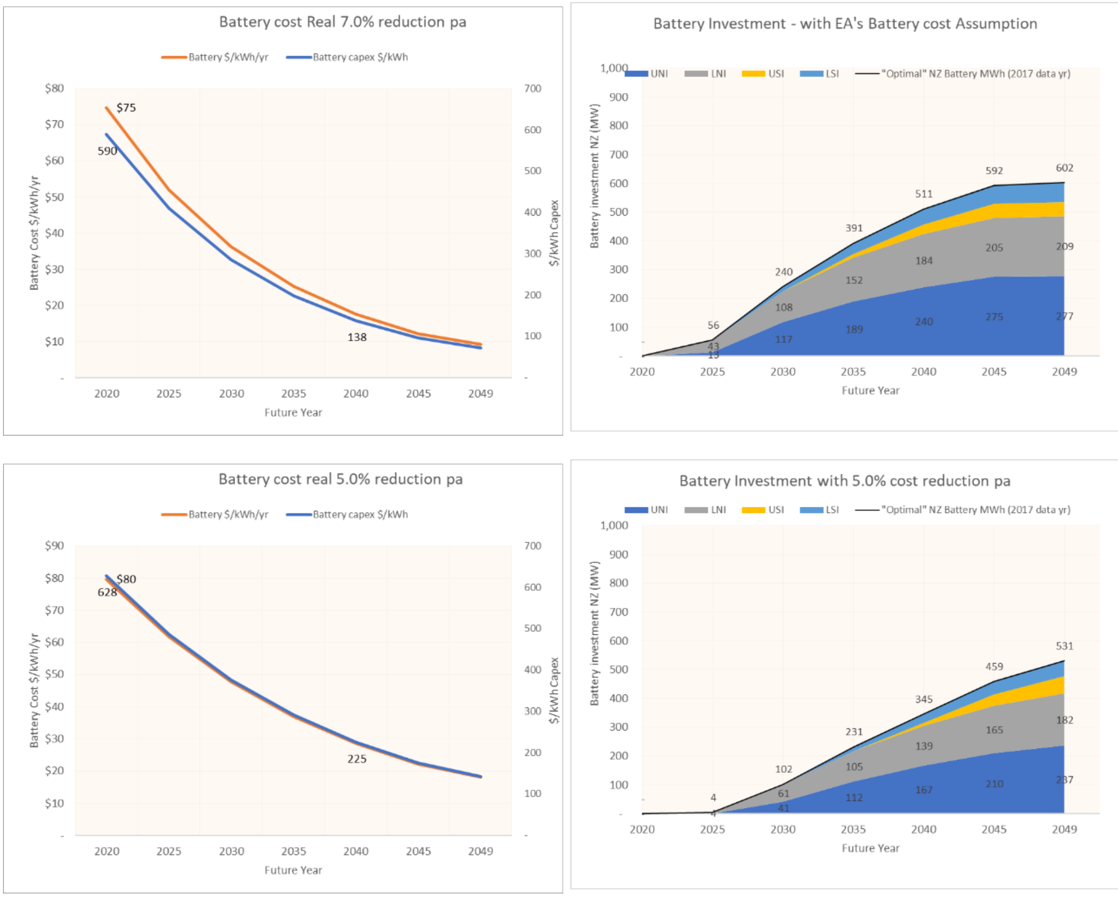

FIGURE 9: BATTERY INVESTMENT RESULTS FOR 5 AND 7%PA BATTERY COST REDUCTION RATES

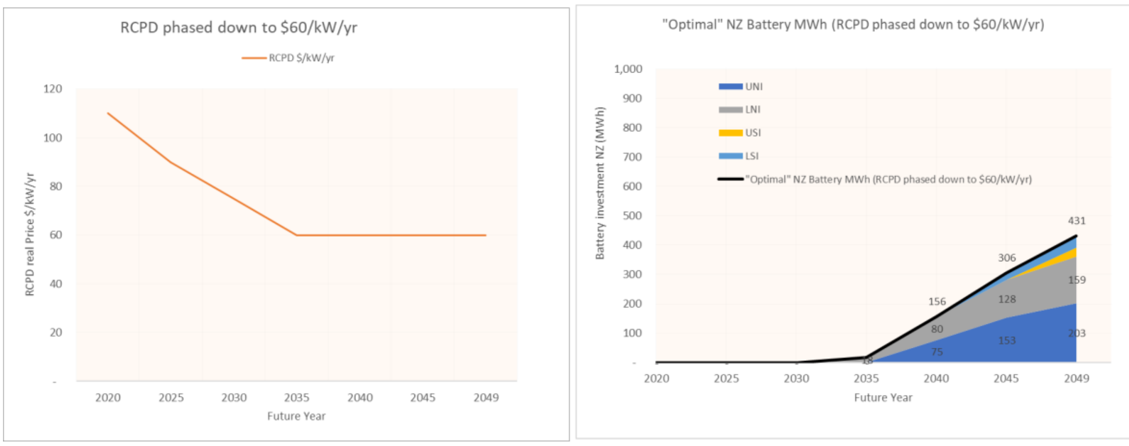

FIGURE 10: BATTERY INVESTMENT WITH 5%PA BATTERY COST REDUCTIONS AND A PHASED REDUCTION OF THE RCPD RATE TO $60/KW/YR BY 2035.

While the analysis presented here is more realistic than that presented by the EA it still is subject to some limitations[v], however these do not materially affect the key conclusions.

1.8 COMPARISON WITH EA RESULTS

The chart below compares the results of this analysis with the EA results. The EA forecast that battery investment will rise very rapidly between 2030 and 2040, before reaching an arbitrary limit in 2045.

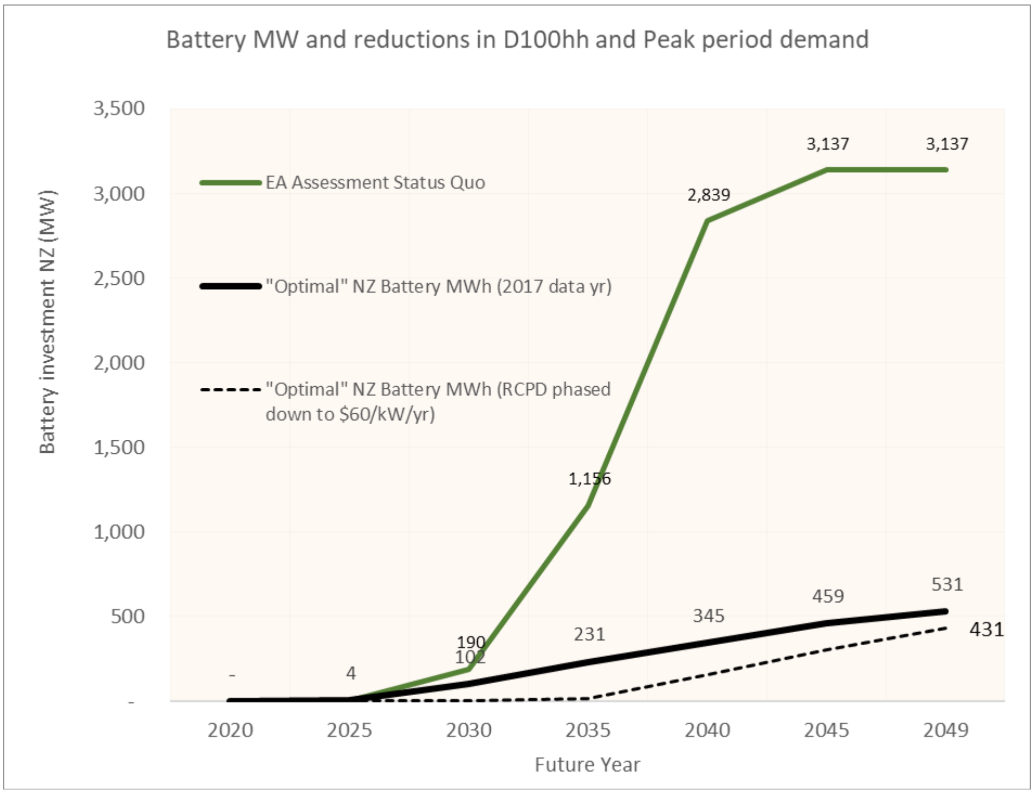

FIGURE 11: COMPARISON OF EA BATTERY INVESTMENT PROJECTIONS WITH THIS ANALYSIS

The EA forecast does not account for the declining marginal RCPD value of batteries or the impact of batteries in flattening the top of the load duration curve. It also assumes an unrealistic peak avoidance strategy which has 4 to 7 cycles of battery operation for each day over 5-6months. This assumes that batteries can be filled repeated during peak times, when chronological analysis shows that typically only 2 cycles can be achieved, that charging must be carefully managed to avoid creating new peaks, and that RCPD savings can only be made on a fraction of the days within the 5-6 month period they assume.

This report's analysis recognises these limits and results in a forecast which is only 1/6th the level the level. By 2045, this is lower than the battery investment forecast by the EA under their TPM proposal without an RCPD.

This report's analysis also shows that a peak avoidance strategy aimed at reducing the top 100 half hours of peak demand will have a much lower impact on average "peak" period demand, than assumed by the EA. The EA assumed that the peak avoidance strategy would reduce the average

MW in their peak period (800 hours) by around 1300MW by 2045, whereas this analysis shows that around 130MW reduction in the top 50 hours demand might be achieved, but less than 10MW averaged over the top 800 hours once resorting of demands by half hour is accounted for.

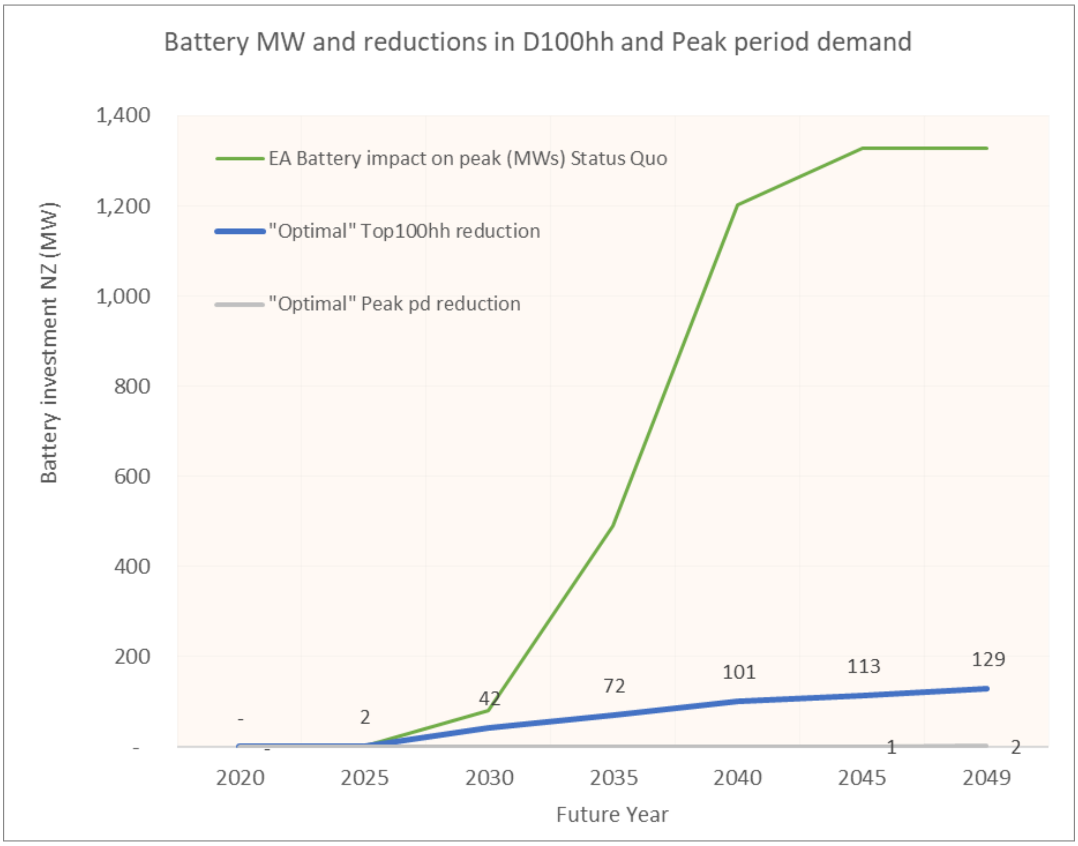

FIGURE 12: COMPARISON OF EA'S ESTIMATED IMPACT ON PEAK PERIOD DEMAND WITH THIS ANALYSIS

1.9 CONCLUSIONS

This more refined analysis of the incentives for "excess" battery investment to avoid RCPD charges indicates that:

- Even if the current RCPD is maintained in real terms at around $110/kW/y;
- The maximum additional battery investment to avoid RCPD charges is estimated to be 400-500 MW (compare with around 3,100MW in EA's CBA).

This means that the level of investment in batteries arising from retention of the RCPD would be minimal[vi], and more than offset by the cost of increased peak from removal of existing levels of ripple control (etc) arising from complete removal of an RCPD signal[vii], and the long run cost of bringing forward transmission investment, estimated by the EA as $60/kW/yr[viii] for the purpose of their CBA.

If there was a concern that the costs of bringing forward investment in 200-300MW of batteries before 2035 outweighed the benefits, then this could be simply addressed by phasing down the RCPD to a lower level over that period. This would be a low risk strategy which would ensure that existing low-cost ripple control would be retained and the phasing down of the RCPD could be adjusted over time as and when the changes relating to technology costs, solar and EV emerge in the future and, as and when changes relating to real time nodal spot pricing and demand response are confirmed.

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[i] Note that optimum is in quotes as there are many uncertainties involved in the scheduling of batteries to obtain benefit from either price arbitrage or peak avoidance. Actually, there are be a number of strategies which will provide a similar benefit, and this benefit will be subject to a high level of uncertainty. For this report the "optimum" is found by simulation over a range of parameters for selected strategies operated over typical historical years. While these strategies do not assume full foresight, they are still somewhat optimistic as discussed further below.

[ii] The EA reference Bloomberg New Energy Outlook 2018 which indicates an 8%pa decline to 2030. But they fail to recognise that this cost reduction is for Li battery packs only, not a full utility scale system. When the balance of plant and other costs of a utility scale system is accounted for the rate of reduction to 2030 is only around 5%pa. In addition, it should be recognised that Bloomberg's rate of decline is to 2030 only and applying this rate out to 2050 is not realistic since their forecasts indicate that decline rates are likely to fall over time.

[iii] The marginal cost of new batteries is expressed as an annual cost (capital recovery and fixed operation) per kWh of battery energy capacity (e.g. the annual cost per kW for a battery with 1-hour working storage capacity).

[iv] The analysis assumes a single coordinated battery operation for all batteries in the region (possibly provided by an aggregation agent with knowledge of zonal loads in previous trading periods by imperfect forecasting of the target load line and zonal loads in the trading periods ahead). This provides an optimistic estimate of the value of batteries in reducing RCPD costs. In reality, there will be a number of battery and load control operators within a region which will make it more difficult to get value from avoiding RCPD – particularly as the combined level of batteries, ripple control and distributed generation gets larger.

The analysis also assumes a price arbitrage value which does not decline as additional batteries are installed. In reality the price arbitrage value will also actually fall as more batteries are installed. This means that the estimated extent of "distortion" from new investment will be somewhat overstated.

[v] The analysis is based on a set of 3 historical years (2016/18) of net demands and spot prices. The zonal totals are derived by adding relevant GXPs, which closely approximate Transpower's published zonal demand. For convenience the results for the 2016/17 year are illustrated in the appendix, but the general conclusions hold for the other years. The

main difference relates to the estimate price arbitrage benefits, which varies from around $7 to $15/kWh/yr. during the 3 historical years as a result of hydrology. For the forecasts an average figure of around $12/kWh/yr. is used.

A RCPD charge will apply differently each year depending on demand growth, the weather and performance of ripple control and battery operation. This means that there will be a bit of variability in the returns expected from new investment and investors will need to take this into account when making their investments. The forecasts to 2049 do not explicitly account for general demand growth, however this is not major issue as 20% increase in demand to 2035, only has a 10-20MW impact on the battery investment.

Future price volatility may increase the value from energy price arbitrage compared with this analysis, but this does not substantially affect the general nature of the declining value of additional MWh of batteries to avoid RCPD charges or the broad conclusions.

It's also possible that cheaper forms of battery storage may become available (e.g. from EVs if they are grid connected, however it's not clear that will be available at the critical times required (e.g. when customers come home in winter evenings). It's also possible that EVs may themselves increase peak demands.

The nature of demand peaks is likely to change as more distributed rooftop solar and EV's are installed. This will change the nature of the net demand curve. The RCPD signal will provide a naturally self-limiting signal for the management of ripple control and batteries to meet this change.

[vi] The EA estimates $202m NPV cost for investment in extra batteries as a result of retaining the RCPD transmission price signal. This refined analysis indicates a maximum NPV cost of approx. $50m , which is offset by avoided transmission costs estimated (using the EA's CBA estimates of cost per MW) of between $50m and $60m assuming that the increase in existing peak demand caused by complete removal of the RCPD is at least 100MW. If the RCPD was phased down to a long run level of $60/kW/yr by 2035 then the maximum NPV cost of extra batteries would be less than $10m.

[vii] The analysis in this appendix does not specifically address the potential impacts of removal of the RCPD signal entirely. It is estimated that currently around 600MW of ripple control etc are being operated to reduce the top 100hh peak. There is a risk that complete removal of the RCPD signal might cause a significant jump in the top 12 or top 100 hh peak demands. The exact level is difficult to determine as it's possible that there may still be some management of peak demand in response to spot price signals and to deal with distribution constraints. However, it's quite likely that these the peak could increase by 200-400MW, which could result in higher spot prices and the emergence of new transmission and distribution peak constraints.

[viii] See page 46 of the EA Issues paper. The EA estimates $421m NPV transmission cost for their proposal which has an extra 5377MW NPV peak demand. Thus, the implied levelized incremental transmission cost bought forward is $78/kW/yr = 421/5377*1000. This is adjusted by 0.77 to exclude overheads (which they say are unlikely to be driven by increased peak demand) giving a net $60/kW/yr.

FINAL

Prepared For:

The TPM Group

Review of Transmission Pricing Guidelines Issues Paper 2019

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1. SUMMARY

1.1. OVERVIEW

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

1.2. EMERGING THEMES

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

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

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

- Retain the RCPD charge but reduce it significantly by spreading it over more hours to the point where it is recalibrated to be no greater than the long-run avoidable cost of transmission as estimated by Transpower;

- Do not adopt the beneficiary pays orientation as proposed, but rather first resolve the many prerequisites required to enable a beneficiary pays approach to be effective in the New Zealand context; and

- Do not revisit the legacy investments, with the exception of the HVDC.

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

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

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

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

1.3. Key Challenges

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

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

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

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

- **Resolve the HVDC Charging Regime.** The HVDC charge for historically incurred HVDC investments, which is currently imposed only on South Island generators (though it was once allocated very differently), is unfair and distortionary, and should be resolved in a simple, practical way – even if it requires a unique treatment; and
- **The Perfect is the Enemy of the Good.** A flexible, incremental “learning” approach is warranted. The energy world is clearly changing with the prospect of numerous emerging and future sources of disruption, so the prospect of a once-and-for-all solution is unrealistic, though the underlying principles and concepts supporting an evolving solution appear robust.

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

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

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

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

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

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

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

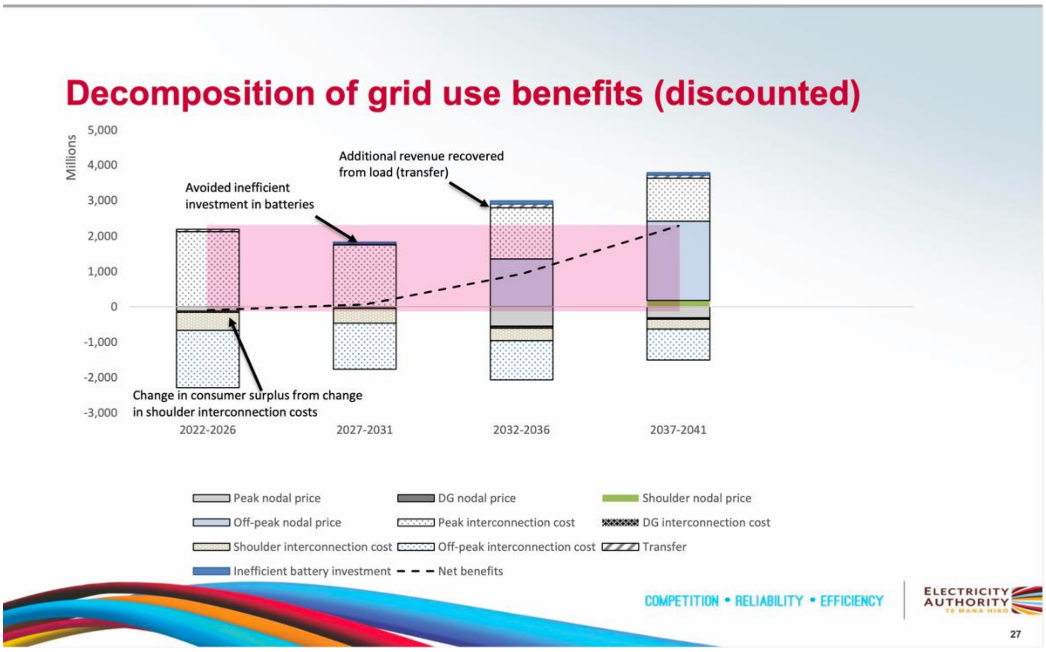
It is generally not good analytical practice to jump from a BAU case that starts with a clear economic flaw to an extreme case at the other end of the spectrum unless the point is simply to hammer home a high-level headline message. There is a middle ground of prudent and attractive and relevant options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

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

1.5. Timing

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

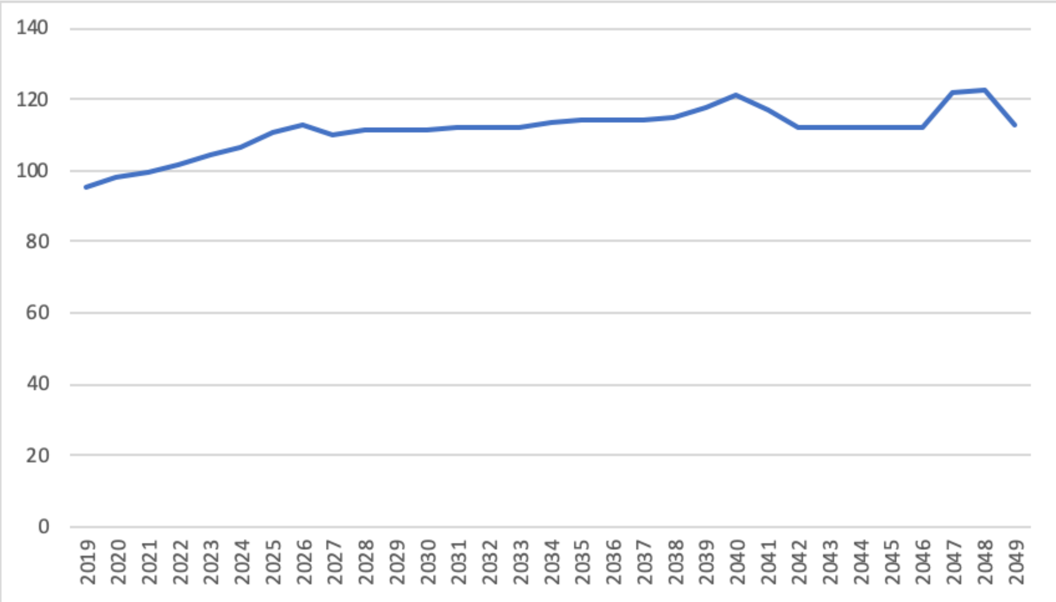
Figure 1: CBA Estimate of Grid Use Benefits Over Time



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

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

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



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

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

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

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

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

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

1.6. A Principled Solution

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1.7. Summary: The Vanguard is a Risky Place

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

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

- The loss of an important price signal by removing the RCPD charge and moving to full reliance on LMP for both dynamically efficient grid use and generation investment. Avoidance behaviour might be slowed but also made less economically efficient as there would be a likely loss of valuable information about end user response to price and the viability of various available behind-the-meter options. Cost-shifting is not desirable per se, but observable behaviour and investment has value. Markets thrive on information about choices.
- A large shock of short-term wealth transfers due to an insufficient transition, compromising durability;
- Unexpected difficulties implementing (and realising benefits from) a beneficiaries pay approach in practice, potentially leading to delays in transmission projects and higher costs; and
- The level of disputation may not go down, compromising many of the benefits claimed, particularly in relation to beneficiaries, as many transmission projects have wide and diverse benefits such that the incremental "benefit" from more granular or refined cost allocations would not be worth the contentiousness the new process would invite.

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

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

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

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

2. RESPONDING TO CHANGING DYNAMICS

2.1. OVERVIEW

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

2.2. INCREASING BEHIND-THE-METER OPTIONS

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

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

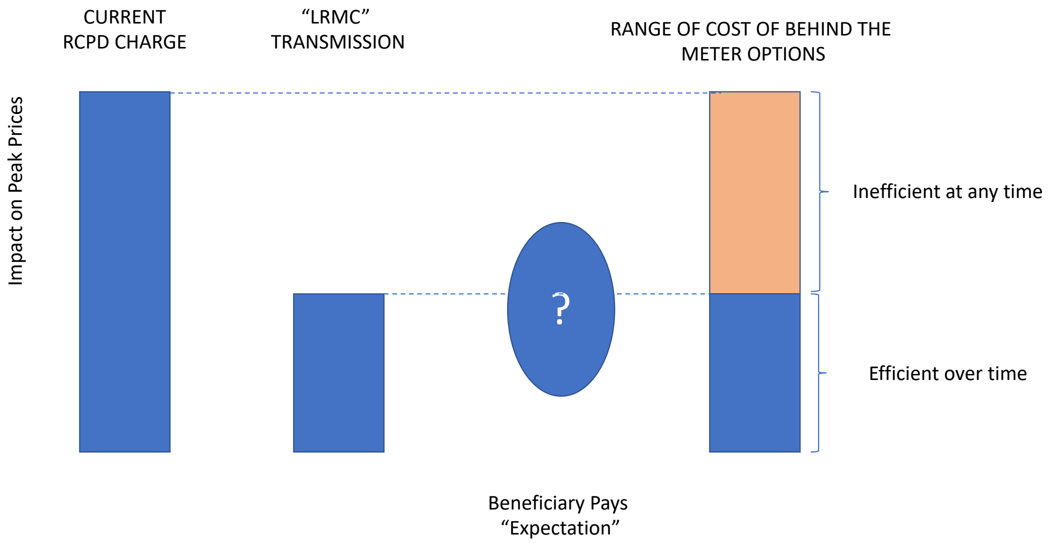
7 A problem with this observation is that any change to peak period elasticity is going to be a function of the RCPD charge. When the charge is too high, then it reduces the cost (increases the attractiveness) of avoidance behaviour during peak periods and makes electricity demand appear to be more elastic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

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

2.3. Customer Response

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

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



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

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

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

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

2.4. Simple Response: Recalibrating the RCPD

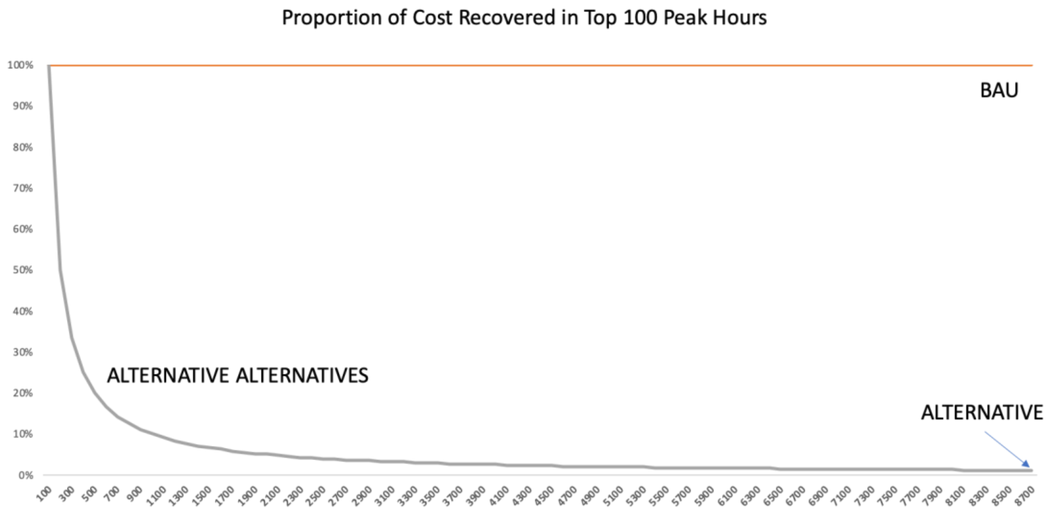
To the extent that, demand-based charges (like the RCPD charge) *are* becoming avoidable at lower costs, then it makes sense to make corresponding adjustments to the RCPD charge itself. It also makes sense to follow such behaviour carefully as it provides a signal as to the availability of options that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

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

2.5. ILLUSTRATING THE OPPORTUNITY

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

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



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

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

3. THE (MANY) CHALLENGES OF BENEFICIARY-PAYS

3.1. OVERVIEW

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

3.2. CHALLENGE: EASY CONCEPT; DIFFICULT AND UNCERTAIN IMPLEMENTATION

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

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

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

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

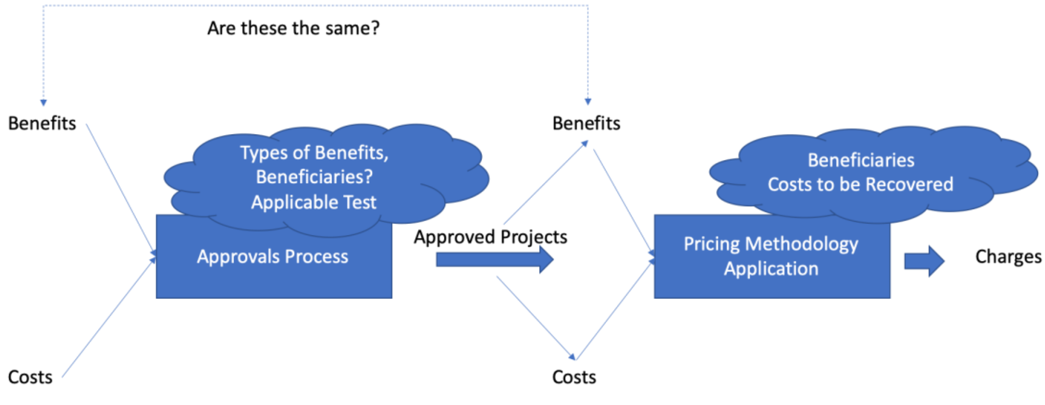
Crucially, the relevant approvals process, itself, must also be clear and comprehensive in relation to how all of the various types of benefits are to be treated, such as reliability, safety, competition, option value/development, and other economic benefits, as each has different potential beneficiaries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

3.3. Challenge: Complicated and Split Process

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

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

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



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

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

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

Alignment depends on three things:

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

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

3.4. Challenge: Different Types and Timings of Benefits

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

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

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

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

(a) For the reliability category, beneficiaries of investments are determined and costs are allocated based on calculating the amount of load that would be shed (without the investment) and who would lose it.

(b) For the economic category, beneficiaries of investments are determined and costs are allocated based on decreases in load's payments for energy as a result of a transmission project. The models estimate or forecast changes in locational marginal prices (LMPs) resulting from an investment for each of 11 cost allocation zones over the first ten years that the investment will be in service. For example, New York City is one of the 11 cost allocation zones[10], and Long Island is another.

(c) For the public policy category, the PSC specifies the allocation process. If there is no specification, the method defaults to a state-wide load ratio share. For public policy projects considered to date, the PSC has specified a portion of the costs to be shared across the state, with the balance allocated in accordance with NYISO's beneficiaries-pay method for economic investments.

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

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

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

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

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

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

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

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

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

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

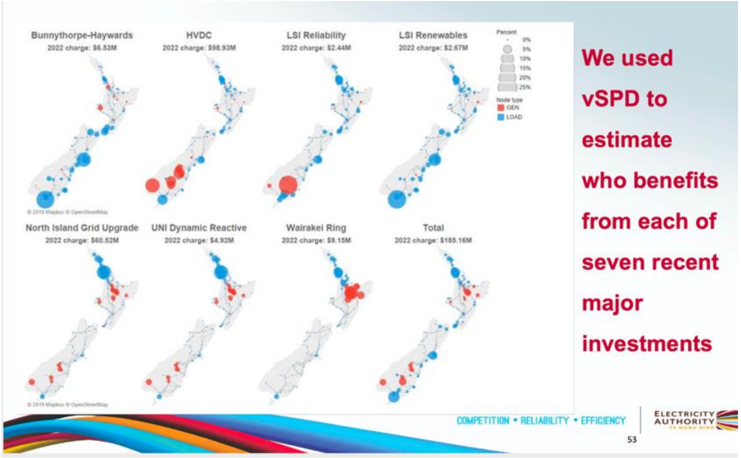
If it was once determined that certain (types of) benefits were likely but then later they do not occur, are the associated costs to be covered only by the now unlucky non-beneficiaries? Was it really up to them? Or was the decision made on their behalf? What if the reason the benefits were not realised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

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

3.4.3. Challenge: Materiality

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

Figure 6: Seven Legacy Projects and their Impact



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

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

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

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

3.4.4. Challenge: HVDC

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

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

3.5. Challenge: What Next?

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

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

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

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

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

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

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

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

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

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

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

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

4. LMP VS RCPD

4.1. Overview

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

> *'Although nodal pricing provides efficient short-run price signals for use of the grid, it does not provide efficient long-run signals. Reliance on nodal pricing is insufficient to promote efficient transmission investment because nodal pricing does not provide a sufficient price signal about the cost of the future transmission investment needed to supply changes in demand for transmission services.'*

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

4.2. Challenge: LMPs

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

- First, LMP *is* only short-term in nature and amounts to a volatile competitive market price signal often without a corresponding long-term contractual hedge available.

- Second, the New Zealand market is small with workable competition at best. The transmission network is long and stringy with many implications for competition and reliability and relatively fewer projects that would be dominated by economic considerations.

- Third, New Zealand is committed to decarbonisation which automatically infuses all planning scenarios and stakeholder expectations with the likelihood or even inevitability of future policy intervention or guidance to assure achievement – with likely implications for transmission development that go beyond LMP considerations.

- Fourth, the wholesale market itself has been subject to numerous reviews – some quite deep and wide-ranging – canvassing market structure, market power, hedge market performance, hydro management, dry year reserve policy, and retail pricing. LMPs may be technically mature in New Zealand, but the market is no more insulated from broader forces and factors than any other.

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

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

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

4.3. Challenge: Attributing Benefit to Beneficiary Participation

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

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

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

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

4.4. Challenge: Dynamic Efficiency

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

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

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

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

4.5. Summary

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

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

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

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

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

5. THE CBA

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

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

5.1. BIG DIFFERENCE IN; BIG DIFFERENCE OUT

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

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

5.2. More Efficient Grid Use

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

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

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

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

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

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

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

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

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

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

5.2.2. Elasticities of Demand

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

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

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

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

5.2.3. Confusing Consumer Welfare Effects

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

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

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

5.3. Investment in Grid-Connected Generation

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

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

5.4. Investment in Distributed Energy Resources (Batteries)

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

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

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

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

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

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

5.5. Missing Risk Framework

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

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

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

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