Should beneficiaries pay for existing grid assets?

Pros and cons of applying an area-of-benefit charge to recover the costs of historical transmission investments

Discussion paper

8 May 2018

Market Design

This information is provided in confidence to Professor William Hogan for the purposes of review and discussion with Electricity Authority Board members and staff.
Prepared by staff, not the Board's view.

Executive summary

This paper sets out the pros and cons of applying a beneficiaries-pay approach to recover the costs of historical investments (i.e., existing assets) in the transmission network. The Electricity Authority Board wishes to discuss with Professor Hogan the specific features of the New Zealand electricity industry and transmission network that may be relevant to its consideration of these matters. This paper is provided to Professor Hogan in order to inform his discussion with the Board.

In this paper we tentatively conclude that the advantages of applying a beneficiaries-pay approach to existing assets, in the New Zealand context outweigh the disadvantages. The most important factor in our view is that applying such an approach only to future investments would not lead to a durable transmission pricing regime. It would require some customers to continue paying for existing assets (many of which are relatively recent) from which they do not benefit, whilst also paying the full cost of future investments from which they do benefit. This could result in perceptions of unfairness, undermining the durability of the regime. We also observe that applying a beneficiaries-pay approach only to future investments could, in theory, distort decisions about where to locate for newly connecting generation and potentially industrial load customers. This concern could arise in practice, as significant transmission network investments are expected to be made in the coming decade (although the materiality of the impact on decision-making around location is unknown).

We also consider the practical implementation difficulties of applying a beneficiaries-pay approach to existing assets. We conclude that these difficulties might be less severe in New Zealand's case, given that here the predominant pattern of flow on the backbone grid is more predictable than in many other countries. The difficulties could also be contained by applying the beneficiaries-pay approach to a limited subset of high-value transmission investments for which high-quality data exists. (Although this would not completely solve the location distortion problem noted above.)

The paper also examines the argument that applying a beneficiaries-pay approach to existing assets would undermine regulatory certainty. We do not accept this argument, as the standard approach in New Zealand is that changes to existing regulations are applied equally to both future investments and existing investments.

The remainder of this paper is structured as follows:

- Section 1 sets out background material on various matters including the current rules for allocating the cost of transmission investment.
- The beneficiaries-pay approach proposed by the Authority in 2016 and the rationale for its application to future transmission investments are briefly discussed in section 2.
- In section 3 we set out the advantages and disadvantages of extending the beneficiaries-pay approach to existing assets (in addition to future investments). In this section we focus on the primary question of whether the AoB charge should be applied to existing assets.
- In section 4 we discuss the question of whether, if the beneficiaries-pay approach is to be applied to existing assets (in addition to future investments), it should be applied to all existing assets, or just to a subset of existing assets.

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1 Background

1.1 This section sets out background information on:

(a) the roles of the Electricity Authority and other relevant organisations

(b) the existing rules for allocating the costs of transmission investment

(c) the Authority's transmission pricing review

(d) the current situation and the need for this paper.

Roles of Transpower, the Commerce Commission and the Electricity Authority

Transpower

1.2 Transpower New Zealand Limited (Transpower) is the owner and operator of New Zealand's national transmission network. Transpower is the only provider of transmission services in New Zealand (although some distributors also own high voltage lines). In New Zealand there is no policy objective to establish a competitive market for transmission network ownership (as there is in some US jurisdictions).

1.3 Transpower is also the system operator for New Zealand's wholesale electricity market.

Commerce Commission

1.4 The Commerce Commission is a separate regulatory entity to the Authority. It, inter alia, is responsible for assessing and approving Transpower's capital expenditure proposals and determining the regulated revenue that Transpower is able to recover from its customers through transmission charges.[1]

1.5 Total transmission charges are currently around NZ$990 million/year. Transpower's regulatory asset base is around NZ$5 billion.

Electricity Authority

1.6 The Electricity Authority (Authority) sets the rules governing the allocation of Transpower's regulated revenue between transmission customers, which are set out in the transmission pricing methodology (TPM), i.e. "who pays" and "how much".

1.7 Transmission customers are:

(a) generators

(b) (large) consumers directly connected to the grid

(c) distributors (who pass the charges on to their customers, the retailers, and ultimately to end-consumers).

1.8 The Authority is responsible for the TPM, although Transpower also has a key role. In more detail:

(a) the Authority determines a set of guidelines that guide Transpower in developing the TPM and which also place constraints on how the TPM can be changed

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[1] If the Commerce Commission decides to approve capital expenditure, the value of the asset at commissioning is added to Transpower's regulated asset base. The regulated asset base is used to calculate Transpower's maximum allowable revenue, through a typical "building blocks" approach (which also involves determination of the cost of capital, annual depreciation and allowed operating expenditure).

(b) Transpower develops a proposed TPM (which must be consistent with, inter alia, the TPM guidelines and the Authority's statutory objective) and submits it to the Authority

(c) the Authority reviews the proposed TPM and can approve, request amendments or (ultimately) amend the TPM directly.

1.9 The purpose of the TPM is to ensure that (with certain provisos) the "full economic costs" of Transpower's transmission services are allocated in accordance with the Authority's statutory objective of promoting competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.

1.10 The Authority's interpretation of its statutory objective focusses on total efficiency, not consumer surplus. Wealth transfers between parties are not taken into account, except to the extent that such wealth transfers give rise to efficiency effects. The Authority is not able to consider arguments based directly on fairness or equity. However, indirect effects on efficiency may be identified; e.g., perceptions of unfairness might be considered likely to impact on the durability (i.e., the level of acceptance) of the regime. This might involve ongoing lobbying and resulting uncertainty, and so additional costs, which can be taken into account in the Authority's decision-making. Refer to Appendix B for further information on the Authority's interpretation of its statutory objective.

The existing TPM

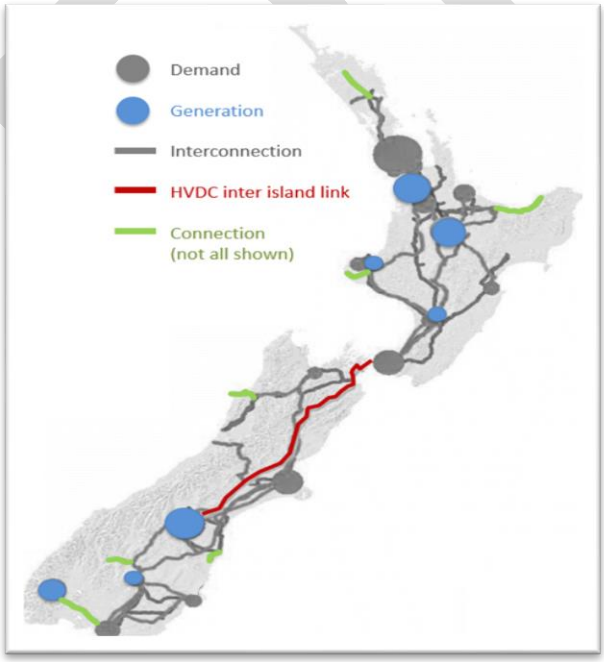
1.11 The existing TPM defines three categories of transmission assets:

(a) connection: assets that connect parties to the meshed grid

(b) High Voltage Direct Current (HVDC): the link between the South Island and the North Island (location of most load customers)

(c) interconnection: the interconnected meshed grid (all other assets).[2]

Categories of transmission assets



2 As is evident in the diagram, New Zealand's grid is not highly meshed relative to some other systems.

1.12 Taken together, interconnection assets and HVDC assets can be termed “interconnected transmission assets” or “interconnected grid assets”.

1.13 The existing TPM has three main charges, corresponding to the three types of grid assets:

(a) a **connection charge** that recovers the costs of assets connecting a participant to the grid. This charge is paid for by the connecting party or parties (connection charges make up 13% of Transpower’s revenue)

(b) an **HVDC charge** to recover the costs of the HVDC interisland link. These charges are required to be allocated to only South Island generators based on their injections (HVDC charges make up 15% of transmission revenue)

(c) an **interconnection charge** to cover the cost of the rest of the transmission system, which are essentially interconnection assets. Interconnection costs are required to be socialised amongst load customers on a “postage stamp” basis. Only load customers pay the interconnection charge. The interconnection charge is a uniform national $/kW rate. Each load customer’s interconnection charge is based on the customer's kW demand during the 100 trading periods in a year with the highest regional coincident peak demand (RCPD periods). There are four regions which cover the whole of mainland New Zealand. Interconnection charges make up 72% of transmission revenue).

1.14 Refer to Appendix A for further information on the existing TPM.

The Authority’s transmission pricing review

1.15 The Authority is reviewing the guidelines that Transpower and the Authority must follow in setting the TPM. We are aiming to determine whether a revision to the current TPM might better promote the Authority’s statutory objective and deliver long term benefits to consumers.

1.16 In 2016, the Authority identified a number of inefficiencies caused by the current TPM,[3] and proposed a number of changes to the TPM guidelines. The proposed changes (termed the 2016 proposal) are discussed in section 2 of this paper.[4] The core of the 2016 proposal was a beneficiaries-pay approach to allocating the cost of interconnection and HVDC assets in New Zealand (replacing the existing interconnection and HVDC charges).

1.17 In early 2017, (after consultation on the proposal had been completed), the cost-benefit analysis (CBA) for the proposal, which was prepared by an independent party, was found by the Authority to have flaws, which were sufficiently serious that the Authority could no longer reasonably rely on the CBA as a basis for decision-making. Accordingly, the 2016 proposal has not been progressed further.

1.18 Subsequently (in mid-2017), a number of new members were appointed to the Authority Board (Board). The new Board members have been briefed by staff to enable them to get up to speed and fully understand the complexities of the TPM review and the process to date.

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3 These inefficiencies are set out in Appendix C.

4 The Authority laid out its then proposed changes to the TPM guidelines in the publications *Transmission Pricing Methodology: Issues and Proposal: Second Issues Paper* 17 May 2016 and *Transmission Pricing Methodology: Second issues paper Supplementary consultation* 13 December 2016. In this paper we refer to the complete proposal set out in these two papers as “the 2016 proposal”.

Current situation

1.19 The Board has not yet made any decisions in relation to amending the current TPM. The Board is currently considering a number of matters that in its view require further consideration. One of the most significant matters is the question of the scope of the application of a beneficiaries-pay approach. In particular, should such an approach be applied:

(a) only to future investments

(b) to future investments and all existing assets

(c) to future investments and a subset of existing assets (such as major investments made since 2004) – or to future investments and the HVDC assets.

1.20 In the 2016 proposal, the beneficiaries-pay approach was to be applied to future investments and to a subset of existing investments (including the HVDC assets as well as major investments made since 2004). The proposed application to existing assets was a significant and contentious issue in submissions in response to the 2016 proposal.

1.21 Board members have expressed a desire to hear directly from Professor William W. Hogan, to inform their consideration of this matter, on the basis of his international leadership in the policy debate on cost allocation for transmission networks. Board members are also keenly aware of Professor Hogan's key role early in the development of New Zealand's electricity market.

1.22 The Board is particularly interested in engaging with Professor Hogan on the question of whether a potential beneficiaries-pay approach in New Zealand should be applied:

(a) to interconnected grid assets commissioned after the date on which the final guidelines are published (future grid investments) only, or

(b) to both future grid investments and some (or all) existing grid assets.[5]

1.23 The Board wishes to discuss with Professor Hogan the specific features of the New Zealand electricity industry and transmission network that may be relevant to its consideration of this question.

1.24 The Board is also interested in any observations Professor Hogan may have on any other aspects of the beneficiaries-pay approach the Authority proposed in 2016.

1.25 This paper is provided to Professor Hogan in order to inform his discussion with the Board.

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5 If a potential beneficiaries-pay approach was to be applied to future investments and to a subset of existing assets, the subset could include: major investments made since 2004, just the HVDC assets, or both major investments made since 2004 and the HVDC assets.

2 The Authority's proposed area-of-benefit charge

2.1 The Authority in 2016 proposed to introduce a system of cost allocation commensurate with the distribution of benefits for interconnected grid assets in New Zealand.[6]

2.2 The Authority made the proposal in order to address a number of problems with the current TPM that it had identified.[7] In summary, the Authority found that, in relation to the interconnection and HVDC charges, there were three main problems with the TPM:

(a) *Poor price signals are incentivising inefficient use of the interconnected grid, inefficient levels of grid investment, and inefficient investment by grid users.*

Charges for the interconnected grid send poor price signals for use of the interconnected grid, which affects a wide range of investment decisions.

(b) *Poor price signals are causing inefficient participation in decision-making in regard to the interconnected grid, which leads to inefficient grid investment decisions.*

(i) Participants face incentives to pursue grid investments that provide net private benefits to those benefiting from the investment, but are not efficient overall. This arises because the current charges mean they either contribute little to the cost of the investment compared with the benefit received, or do not have to contribute to it.

(ii) Participants do not face incentives to participate in ways that support the discovery of efficient transmission investment options (including alternatives to transmission) through the transmission investment approval process.

(c) *The current TPM is not durable.*

The interconnection and HVDC charges harm the durability of the current TPM. Poor durability exacerbates long-term uncertainties, potentially causing grid users to make inefficient location and investment decisions. It also results in resources being directed at lobbying for fundamental changes to the TPM that would not occur with a more efficient TPM.

Recent developments in emerging technologies reinforce the view that the current TPM is not durable. For example, expected reductions in the prices of large-scale batteries will make it profitable in the near future for parties to install batteries to manipulate demand to avoid transmission charges.

2.3 The key charges under the 2016 proposal were as follows:

(a) An area-of-benefit (AoB) charge to be levied on generator and load customers to recover the costs of interconnected grid assets. The AoB charge would recover the full cost of an investment from those who benefit from it (both generator and load customers), in proportion to the benefit they derive from it. The full cost includes recovery of the capital cost over time (i.e., depreciation), cost of capital and operating and maintenance costs.

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6 This paper provides only a brief summary of selected key aspects of the proposal, focussing on the AoB charge. For a more comprehensive discussion of the proposal, refer to the publications *Transmission Pricing Methodology: Issues and Proposal: Second Issues Paper* 17 May 2016 and *Transmission Pricing Methodology: Second issues paper Supplementary consultation* 13 December 2016. Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/ .

7 These inefficiencies are set out in more detail in Appendix C.

(b) A connection charge to recover the cost of connection assets from connecting customers (substantially similar to the existing connection charge, with some relatively minor amendments). The Authority was largely satisfied that the existing connection charge was already consistent with the beneficiaries-pay principle.

(c) A residual charge: a broad-based, socialised, low-rate charge on load customers, not intended to provide any price signal, to recover the remaining costs (including the costs of any network investments not recovered through the other charges). The connection and AoB charges, along with nodal pricing in the spot electricity market, were intended to provide price signals for efficient grid use and efficient investment decisions.[8] So, the residual charge was designed to collect remaining revenue with minimum impact on grid use and investment decisions.

2.4 This paper focusses largely on the AoB charge, rather than the other elements of the 2016 proposal.

Proposed AoB charge

2.5 The chief element of the proposal was that the TPM should include an AoB charge to recover the costs of interconnection and HVDC assets. The AoB charge would recover the full costs of a transmission investment from both generator and load customers located in the areas identified as benefiting from the investment, in proportion to each customer's share of the private benefits from the investment.[9]

2.6 The Authority proposed that the AoB charge should apply both to future grid investments and to some (or all) existing interconnected grid assets. Investments to which the AoB charge would apply were known as "eligible" investments. The following subsection focusses on efficiencies from the application of the charge to future investments.[10] Future application of a beneficiaries-pay charge is relatively widely accepted, and applied in some overseas jurisdictions and so can be discussed first (briefly), before turning to the main topic of this paper, which is the proposed application of the AoB charge to existing assets. This topic is discussed in section 3 of this paper.

2.7 Some of the key features of the AoB charge proposed by the Authority were as follows:

(a) Generation would pay the charge, as would load customers (distributors and grid-connected industrials).

(b) Charges would be calculated for each individual customer in proportion to its share of the positive net benefits expected over the life of each eligible investment.[11]

(c) The method would be required to:

(i) for each eligible investment, identify the areas of benefit. An area of benefit is an area in which at least one designated transmission customer is expected to receive a positive net benefit from the eligible investment

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8 The proposal also provided for an additional charge which could potentially be applied in circumstances where nodal pricing was insufficient to signal incremental costs (referred to as an LRMC charge).

9 The Commerce Commission requires Transpower to consider not only transmission network upgrades but also non-transmission solutions to identified deficiencies in the grid. The AoB charge would also recover the costs of any payments by Transpower in respect of a non-transmission solution.

10 In order to promote efficient investment, the charge would apply to replacement, refurbishment and upgrades, as well as new investment.

11 In this context distributors are regarded as proxies for their customers. That is, any benefit that accrues to a distributor's customers would be attributed to the distributor.

(ii) determine the extent of the benefit for each area

(iii) allocate charges to generation customers and load customers in an area of benefit in proportion to the aggregate expected positive net benefit to generation and load customers.

(d) The AoB charge is intended to function as a fixed charge. Charges are to be determined ex-ante (rather than being revisited on a regular basis).[12] However, the proposal provided for three limited exceptions to this rule, under which charges could be revisited (in the case of high value investments only):

(i) the "optimisation" process, under which, if there has been a material reduction in the use of the assets subject to the AoB charge, transmission customers could apply for a reduction in the value of assets (which would reduce the AoB charge applying to those assets)[13]

(ii) the "material change in circumstances" process, under which Transpower would determine (after consultation) if there had been a material change in circumstances, and adjust AoB charges accordingly.[14] The main consultation document for the proposal noted that a significant divergence between expected and actual benefits of high value investments is an example of such a material change

(iii) new entrant connections (discussed below).

New entrant connections

2.8 If a new customer connects to the interconnected grid and Transpower takes the view that this is not a material change in circumstance, it was proposed that Transpower would establish the AoB and residual charge for the new customer as follows:

(a) assess the charges for the new entrant as if the entrant had been connected to the grid at the time the new TPM was implemented. The AoB and residual charges for the new customer must be based on a proxy for, but not dependent on, the physical capacity after the participant becomes a designated transmission customer

(b) apply the charge from the time the entrant connects to the interconnected grid

(c) adjust (scale down) each other customer's AoB and residual charges down so that:

(i) in total, all charges raise the revenue required

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12 For existing investments similarly, charges are to be determined at the outset of the new TPM and not revisited except in limited circumstances.

13 The proposal to allow optimisation for AoB assets was intended to make the charge market-like—i.e., to reflect the kinds of outcomes that occur when willing buyers and sellers negotiate outcomes in a workably competitive market. A significant downturn in business for a supplier operating in a competitive market doesn't ordinarily lead to higher charges for the supplier's remaining customers, yet that is what could happen under the AoB charge without optimisation. The pragmatic outcome from allowing optimisation is that residential and business consumers in areas of the country that have received substantial grid upgrades—in reasonable anticipation of substantial growth in a couple of major local firms, for example—can avoid most of the consequential rises in AoB charges if the demand hasn't eventuated. As Transpower's total revenue is pre-determined by the Commerce Commission's price control regime under a revenue cap, any optimisation of AoB charges will result in higher residual charges for all load customers. It will not result in lower revenue for Transpower.

14 The proposal specified that the TPM must include a method and process specifying how this would occur.

(ii) the relativity between different customers' (excluding the new entrant) AoB charge and residual charge is maintained.

2.9 The Authority took this approach because of its view that it is important that the new entrant be treated on the same basis as a (possibly hypothetical) existing business that was otherwise identical to the new entrant, but was connected to the grid at the time that the new TPM came into force. To do otherwise would potentially introduce a production distortion. For example, if the new entrant had lower charges than it would have had if it had been an existing business, it may be able to out-compete an existing business when it might otherwise be less competitive. This would be inefficient.

Intended efficiencies from applying AoB charge to future investments

2.10 The AoB charge provides grid users with better incentives (compared to the current HVDC and interconnection charges) to take into account the cost of upgrades to the interconnected grid when making their own operational and investment decisions, and when considering Transpower's proposals for upgrades to the interconnected grid. This should lead them to seek the most efficient investment options overall.

2.11 Most of the benefits that arise from an AoB charge will relate to its application to future transmission investments, rather than its application to existing assets, namely because it will encourage efficient future investment in transmission, generation and load.

2.12 The prospect of future investment in transmission, generation and load, and thus the potential for material efficiency gains, has heightened in recent times due to a number of developments. These developments include:

(a) Transpower forecasting significant transmission investment (more than NZ$200 million per annum) out to 2025.

(b) The growing calls for undergrounding transmission lines and associated prospect of changes to town planning documents to require or facilitate it.

(c) The potential for additional renewable generation to be added to the New Zealand electricity system, some of which could be distant from load.

(d) Technology changes.

2.13 Applying the AoB charge to future investment in the transmission network is expected to increase the efficiency of transmission investments. Unlike with the current postage stamp interconnection charge, the AoB charge would mean that the potential beneficiaries of a particular investment proposal would face incentives to reveal the real benefits to them of various investment options. They would have the incentive to support the investment if its benefits to them outweighed the charge they would have to pay for it and to oppose it if they did not.

2.14 Because the major beneficiaries from a proposed investment would have a substantial stake in ensuring the investment is efficient, they would have a strong incentive to participate in Transpower's decision-making process on the investment, to scrutinise the proposed investment. In particular, it would encourage them to oppose investments where the benefits to them are less than the charge they would have to pay for it. This should increase the quantity and quality of information available to inform the Commerce Commission's decisions on investment proposals. It should also improve the incentives on Transpower to propose investments that meet users' needs.

2.15 Conversely, because those who are not beneficiaries of a proposed transmission investment would not incur an AoB charge for it, the charge would not encourage them to inefficiently oppose the investment.

2.16 This reform could also help to create a culture change towards greater transparency around Transpower's costs more generally. Transpower's overheads for owning and operating the transmission grid are substantial.[15] If transmission customers began to scrutinise these unallocated costs more carefully, this could enhance pressure on Transpower to operate more efficiently wherever feasible.

2.17 Together these considerations would ensure that Transpower has better information and faces stronger incentives than at present to ensure investments are efficient, particularly regarding the timing, size and type of investments. This should substantially increase the quality of transmission investment decisions. It would make it less likely that decisions are made to proceed with an investment when it is not justified, and more likely that decisions are made to proceed with investments that are justified. It would also improve the chances of avoiding investments that are more expensive than necessary.

2.18 More efficient transmission investment would facilitate more efficient investment elsewhere in the industry, as it would alter the economics of transmission compared with alternatives such as generation, distribution and natural gas transmission. The most economic supply of generation services involves trading off the cost of generating electricity locally versus transporting electricity to load areas. Applying the AoB charge to future investments will promote efficient choices between transmission and generation investment while also promoting efficient generation location decisions.[16]

Substantial inefficiencies can be eliminated by replacing other existing charges

2.19 The presumed advantages of the TPM proposed in 2016 are not limited to the improvements in the efficiency of investment that would result from a beneficiaries-pay approach. The proposal would also have improved the efficiency of transmission customers' decisions about their use of the grid, by replacing the current interconnection and HVDC charges.

2.20 These existing charges create significant distortions to customers' decision-making. These distortions largely occur because under the existing TPM, customers can alter the charges they pay by changing their use of the interconnected grid. For example, a customer can reduce its interconnection charge by reducing its peak use, even where capacity is more than sufficient to supply peak demand and peak demand is not increasing over time.[17] Such a customer might have an inefficient incentive to over-invest in distributed generation on its network, for example, in order to reduce its use of the grid at peak times. This incentive may in part explain the fact that the capacity of distributed generation has roughly doubled in the last decade.[18] One major industrial plant operator

15 Transpower's unallocated overheads for owning and operating the transmission grid amounted to $198 million in the financial year 2015/16.

16 Subject to one caveat: the AoB charge appears likely to create a distortion to location decisions by load customers and generation if it is applied to some grid assets and not to others. This is discussed further in the next section.

17 In 2016 the Authority took the view that, to the extent that nodal prices (possibly supplemented by an LRMC charge) provide an efficient signal for use of the grid, further signalling via peak charges would be inefficient.

18 Note that solar panels are not the explanation for this phenomenon, as solar panels make up only a relatively minor proportion of generation capacity in New Zealand.

has managed to reduce its interconnection charge to zero, in part through the use of behind-the-meter generation.

2.21 The 2016 proposal was designed so that – after an investment has been made – transmission customers cannot alter the charges they pay through their use decisions.

2.22 Customers would be largely unable to alter their AoB charges, because these charges are determined ex-ante (with only a limited ability for the charges to be re-determined through the optimisation and material change of circumstances provisions).

2.23 Parties would also be largely unable to alter their residual charge by changing their use of the interconnected grid – even though that charge is allocated in proportion to the size of the customer's load. This is because the method for allocating the residual charge must be (to the extent that it can be economically achieved) designed to ensure that the quantum of residual charge cannot change either as a consequence of the customer's own actions or the actions of any other party (except Transpower). An example would be allocation based on the customer's maximum demand during a specified time period in the past (e.g., the previous five years). The customer therefore has little incentive to alter its use of interconnection assets due to the residual charge.

2.24 So it is clear that significant efficiencies can be gained by replacing or altering the charges that recover the costs of existing assets. However, to gain these efficiencies, the charges that replace the current transmission charges need not necessarily be beneficiaries-pay charges (rather, they need only be difficult to avoid). It is a separate question whether beneficiaries-pay charges should be applied to existing assets. We turn to that now.

3 Advantages and disadvantages of applying beneficiaries-pay to existing assets

3.1 In this section we set out the arguments we have identified for applying a beneficiaries-pay approach, and the AoB charge in particular, to existing assets (in addition to future investments). We also set out the arguments against doing so.

Reasons to apply AoB to existing assets	Reasons not to apply to existing assets
Substantial grid investment has occurred in recent years	Implementation difficulties would be exacerbated
Benefits are relatively predictable in New Zealand's network	Implementation costs would be higher (than for a future-only application)
A future-only application could be less durable	Some stakeholders say it would undermine regulatory certainty (but we don't agree)
A future-only application could result in distortion to location decisions	
Grid maintenance decisions would become more efficient	
Better information would be provided about future investment costs	
Highlighted inefficiencies may lead to better future investment decisions	
Inefficiencies otherwise caused by a high residual charge would be reduced	

3.2 On balance we think that the advantages of applying the AoB charge to existing assets outweigh the disadvantages. The most important factor is our view is that applying such an approach only to future investments would not lead to a durable transmission pricing regime.

3.3 We also consider the practical implementation difficulties of applying a beneficiaries-pay approach to existing assets. We conclude that these difficulties might be less severe in New Zealand's case compared to other countries. The difficulties could also be contained by applying the AoB charge to a limited subset of existing assets (as discussed in section 4).

Reasons to apply AoB charge to existing assets

Substantial grid investment has occurred in recent years

3.4 A number of substantial transmission network investments have been approved in New Zealand in recent years. More than NZ$2.7 billion of grid investment has been approved since 2004 (mostly in the north of the North Island).[19] These recent investments account

19 Around 48 percent of grid investments made since 2004 have been located in the upper North Island (UNI) region (where New Zealand's largest city, Auckland, is located). Four of the largest post-2004 grid upgrades—the North Island Grid Upgrade (NIGU), the North Auckland and Northland grid (NAaN) upgrade,

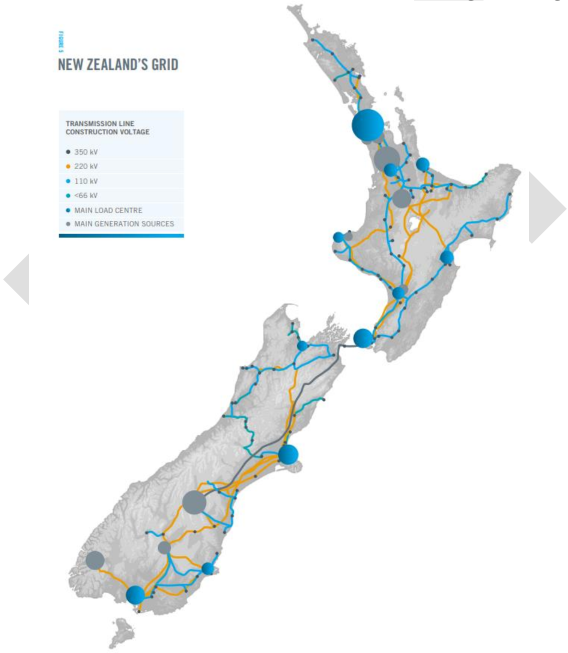
for around 60 percent of Transpower's total regulated asset base (RAB).[20] The ten largest investments in that period were all commissioned very recently: in the years since 2011.

3.5 In this regard New Zealand is different from many other jurisdictions. Other countries (or interconnected systems such as New York for example) are in a situation where major grid investments are *about to be made*. In those other systems, existing grid assets are many years old and they are largely or fully depreciated. Given that there is little value remaining to be recovered, it may be fruitless to apply beneficiaries-pay to these assets. Also the information required to apply an AoB charge (such as the cost of the assets) may not be available in many instances.

3.6 By contrast, New Zealand's position is that we *have recently made* major grid investments. So the majority of existing grid investments (by asset value) are relatively new and only slightly depreciated. Also the information required to apply an AoB charge is available for recent major grid investments (as discussed at paragraph 4.14). In the New Zealand context it is therefore appropriate that the beneficiaries-pay approach be applied to existing network assets (or at least to the recently constructed assets) in addition to future investments.

Benefits are relatively practicable to determine in New Zealand's network

3.7 New Zealand is a long, narrow country, with our largely renewable electricity generation (85%) often located far from the large cities where demand is highest. As a result, our grid is long and stringy and features a high voltage backbone spanning the length of the country (some 2000 kilometres) that links distant generation to major loads. Connected to this backbone are a series of regional grids that serve regional loads and generation.[21]



Source: Transpower, *Transmission Tomorrow*, Figure 5.

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the Otahuhu substation diversity project, and the upper North Island (UNI) reactive support project—were undertaken over the 2011-2014 period, principally in order to maintain or improve transmission service levels to UNI consumers. Excluding the construction and commissioning of Pole 3 of the HVDC, only a (comparatively) small amount of grid investment has been undertaken for other regions since 2004.

20 Transpower's regulated asset base (RAB) was $4.61 billion in 2015/16.

21 Source: Transpower, *Transmission Tomorrow*, p.12

3.8 Today, the backbone grid predominantly carries energy from south to north. This sometimes reverses overnight, as South Island hydro generators conserve water, and periodically reverses in dry winters, when the southern hydro lakes run low.[22]

3.9 The predominant direction of flow on the backbone grid is likely to continue in the future. Transpower has modelled future grid flows under nine different scenarios for forecast demand and generation. Under all scenarios, the predominant flows remain from south to north. The south to north flow trend is driven by the continued growth of Auckland's demand relative to that for the rest of the country. While the scenarios have assumed significant amounts of new generation is built in the Auckland region (in the upper North Island), it is not expected to be enough to counterbalance its growing demand for electricity, requiring more electricity to be imported from the south.[23]

3.10 Given the predominant pattern of electricity flow on the backbone grid is predictable, it follows that the benefits of most interconnected grid assets (including the recent major grid investments) are relatively practicable to determine. For example:

(a) the North Island Grid Upgrade (NIGU) Project was built in order to upgrade the capacity of the grid serving urban centres in the upper North Island, particularly Auckland. Its beneficiaries are likely to be primarily Auckland load customers and generation located to the south of Auckland

(b) the Wairakei Ring Project was built in order to bring energy from new geothermal generation in the central North Island to urban centres in the upper North Island. Its beneficiaries are likely to be primarily upper North Island load customers and central North Island geothermal generation.

3.11 In this regard again New Zealand is different from many other markets. Many other markets have a highly meshed grid, with relatively less predictable flows. In these markets, the pattern of benefits from existing grid assets may be impracticable to determine.

A future-only application could be less durable

3.12 Applying the AoB charge only to future investments involves applying two different charging regimes at the same time: a socialised approach for existing network assets and an AoB approach for investment that takes place after the "cut-off date" (e.g., the date when the new TPM comes into force).[24] This would be unusual from the perspective of the economy as a whole; pricing that varies only because of the date of investment is not usually a feature of workably competitive markets (such as hotels), where price differences reflect service level (e.g., quality and location) not asset age per se.[25]

3.13 Given that a future-only application of the AoB charge involves applying two very different charging regimes at the same time, it might not be durable. This is because a region that required a major investment in the near future would be required to pay for that major investment, while continuing to pay part of the costs of previous major

22 Source: Transpower, *Transmission Tomorrow*, p.12

23 Source: Transpower, *Transmission Tomorrow*, p.14

24 The cut-off date need not be when the new TPM comes into force: it could be another date (such as the date of publication of the Second issues paper in 2016).

25 The use of workably competitive markets as a benchmark for regulated industries is widely accepted as appropriate in New Zealand and this practice has been supported by decisions of the New Zealand courts.

investments from which they do not benefit.[26] This disparity across customers in the relationship between benefits and charges may affect perceptions of fairness, which may undermine the regime's durability.

3.14 The Authority considers a TPM is durable if there is wide acceptance that the general approach is appropriate and that its interpretation is reasonably clear so that any disputes over it are focused on discovering more accurate and robust estimates of key parameters rather than focused on adopting an entirely different pricing approach.

3.15 The current TPM has been subject to ongoing debate and lobbying for over a decade. If the TPM that is implemented is not seen as reasonable, the debate and lobbying would continue. This is costly in itself. More importantly, if a new TPM is seen as unreasonable, it will increase expectations that the TPM will change in future with an unknown change in TPM charges. The long-term uncertainty create by such a lack of durability is likely to create inefficiency through its effect on chilling investment, and potentially through causing grid users to make inefficient location and investment decisions.

3.16 It is not certain that applying the AoB charge to existing assets would be durable. Such an approach might be subject to ongoing lobbying by adversely affected parties. Nevertheless, we think the durability argument against a future-only application is a strong one. This is because a disparity between regions resulting from a future-only application can be considered likely, given that there are regions where there has been significant network investment in recent years (such as Auckland) and other regions where there has not been much investment in recent years (such as Taranaki).[27] The latter regions are likely to require significant replacement and refurbishment investment in the coming years as older assets wear out.

A future-only application could result in distortion to location decisions

3.17 TPM charges should be structured to the greatest extent possible so they do not distort grid users' production and investment decisions. If an AoB charge applies in some locations but not in others,[28] this could discourage generators, and potentially industrial load customers,[29] from connecting to the grid in a location where an AoB charge would apply.

3.18 Given that a future-only application of the AoB charge involves applying two different charging regimes at the same time, it would create inefficient incentives with regard to investment in generation and potentially investment by load customers. This is because under this approach, a newly connecting party (generator or load customer) would pay AoB charges only if it chose to locate in an area where it would be identified as a beneficiary of a transmission investment that has been made since the cut-off date.[30] A number of such areas will exist in the coming decade, given that significant transmission

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26 Several submitters to previous Authority consultations have made this point, including for example Orion. Orion is a distributor located in the South Island. It would appear unlikely to have benefited much from the recent substantial investments to upgrade the grid in the upper North Island.

27 In, Auckland transmission investments made since 2003 make up 89% of the regulatory asset base by value. By contrast, the equivalent figure for Taranaki is only 7%.

28 This effect could also occur if the AoB charge applies in some locations in a way that does not reflect the long-term cost of transmission investment.

29 Industrial load customers could be affected if electricity costs make up a large proportion of the business' total costs.

30 Recall that, for competitive neutrality reasons, charges for the new entrant are set as if the entrant had been connected to the grid at the time the new TPM was implemented (as discussed above in section 2).

network investments are expected to be made (for the reasons noted in paragraph 2.12). The newly connecting party can avoid the AoB charge if it locates in an area that is served only by investments made before the cut-off date.

3.19 The incentive created by the possibility of avoiding the AoB charge may be inefficient, particularly given that new transmission investments, because of increasing returns to scale are more likely than other assets to have spare capacity available. At this stage we don't know how material this incentive would be for generation and load making location decisions. We discuss this location distortion issue further in section 4.

Maintenance decisions would become more efficient

3.20 The TPM determines how Transpower allocates the cost of maintenance of transmission network assets (in addition to other associated costs). The question arises as to whether new maintenance costs from existing assets should be allocated according to a beneficiaries-pay approach. If maintenance costs are allocated via a beneficiaries-pay approach, this could improve the efficiency of asset maintenance decisions.

3.21 One way to achieve this outcome is to apply the AoB charge to existing assets. When an AoB charge is applied to recover the costs of an investment, the identified beneficiaries will pay not only the capital costs of the investment, but also the associated costs, including maintenance of the network assets that make up the investment.

3.22 It follows that, while applying the AoB charge to a historical investment cannot affect the decision to make the investment, it can improve the efficiency of future decisions related to the assets that make up the investment, such as asset maintenance decisions.[31] This improvement is expected to occur because the parties who would pay for the expense (e.g., asset maintenance) would have an incentive to participate in Transpower's decision-making process with regard to the proposed expense, and scrutinise it. We would note that it is not certain that parties would in fact participate in such decision-making with regard to maintenance decisions, as the strength of the incentive is not known at this stage.

3.23 That said, it may be possible to achieve this improvement in efficiency without applying the AoB charge to existing assets. For example, an alternative way to achieve this improvement in efficiency could be to specify in the TPM that the AoB charge will apply to expenditure on maintenance of existing network assets (as well as future investments).

Better information would be provided about future investment costs

3.24 When services delivered by existing assets are priced efficiently, those prices convey information about the likely future cost of the service compared to the cost of alternatives. This helps to drive behaviour that leads to efficient future investments. For example, if it is significantly less costly to deliver electricity to loads that are close to generation, this will encourage generation to be developed close to load and vice versa.

3.25 Alternatively, if customers do not face the full economic cost of the services they receive, then they may make decisions that do not adequately take into account the cost of future transmission investments. So prices that are not cost-reflective can drive inefficient future investment.

[31] Transpower spends over $100m annually on grid maintenance.

3.26 AoB charges are typically designed to be cost-reflective in that they recover the full costs of each investment from its beneficiaries.[32] By contrast, interconnected grid assets that are not subject to an AoB charge are recovered via a residual charge that is allocated on a postage stamp basis across the whole country. It follows that applying an AoB charge to historical investments (i.e. pricing them efficiently) will make better information available about likely future investment costs and so improve the efficiency of future transmission investments.

Highlighted inefficiencies may lead to better future investment decisions

3.27 Applying an AoB charge to existing assets could also influence future investment decisions by increasing transparency regarding the degree of efficiency (or inefficiency) of historical investments.

3.28 This transparency could come about through the optimisation process, under which transmission customers could apply for a reduction in the value of assets subject to the AoB charge if there had been a material reduction in the use of the assets. The increase in transparency would come about through the public consultation that is required as part of the optimisation process. If a historical investment subject to the AoB charge had been inefficiently sized (i.e. built with greater capacity than was required), this would become public knowledge (which could affect Transpower's reputation).

3.29 This increase in transparency could improve Transpower's incentives to make more efficient investment decisions.[33] This is because Transpower would likely wish to avoid such an impact on its reputation, and so its incentive to ensure that future investments were correctly sized would be increased.

3.30 It follows that applying an AoB charge to existing assets could improve the efficiency of future transmission investments.

The inefficiencies otherwise caused by a high residual charge would be reduced

3.31 Application of the AoB charge only to future investments may create greater inefficiency than application to both future investments and existing assets, as the former approach requires a higher residual charge.

3.32 Charging arrangements that involve a higher residual charge create greater inefficiency because the residual charge is not a charge that relates to specific benefits received by the payer of the charge. The overall efficiency of the AoB charge is greater than that of the residual charge, because it leads to more efficient investment and because we know that customers are willing to pay the AoB charge if the investment is efficient. By contrast the residual charge is closer to a pure tax, which will cause some inefficiency. This appears to be consistent with the view of Ronald Coase, who argued that charging the

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[32] This will depend to some extent on the way the AoB charge is calculated, the approach taken to valuation of the assets for purposes of setting the AoB charge and the granularity with which the AoB charge is applied.

[33] Transpower would, of course, have much stronger incentives to make more efficient investment decisions if it was no longer able to recover the costs of "unused and useless assets" (i.e. if optimised assets were removed from its regulatory asset base). However, this is not the case. Under the Commerce Commission's price control regime, once an asset has been included in the regulatory asset base, Transpower is guaranteed to recover the costs associated with the asset.

full costs of providing a service to users of the service was preferable to recovering fixed costs through a tax.[34]

3.33 The economic harm from raising tax-like revenue increases as the tax-like charge increases in a manner which is not proportionate. As a general approximation, if the tax-like charge doubles, the economic costs associated with imposing that charge will approximately quadruple.[35]

3.34 Applying an AoB charge to existing assets will reduce the revenue that is required to be recovered through the residual charge (as it increases the revenue recovered through the AoB charge). So this approach will reduce the economic harm that would otherwise be caused by a high residual charge.

Disadvantages of applying AoB charge to existing assets

Implementation difficulties would be exacerbated

3.35 Applying the AoB charge to existing assets also raises potential difficulties with implementation (as opposed to the cost of implementation, which is treated separately).

3.36 We note that Professor Hogan has written about the difficulties of ex post calculation of benefits:[36]

> *In a sufficiently dense network, any attempt to estimate the benefits ex post, after a particular transmission expansion has been made, would be confounded by the daunting task of separating the network effects and reconstructing a counterfactual that identifies and removes all of the collateral investments in generation, load, and other transmission. The long history of discussion of transmission rights that led to the reform of transmission rights as point-to-point financial rights, rather than describing any particular path in the network, revealed that there is in general no known method for ex post valuation of transmission based on separate flows on individual facilities (Hogan 2002).*

3.37 Transpower raised concerns about implementing an AoB charge on existing assets in submissions to the Authority in response to the 2016 proposal. Transpower noted "*there is considerable uncertainty about whether a robust benefit-measurement method can be developed that is fit for transmission pricing purposes*". Further, Transpower noted that the problems around estimation of benefits "*are likely to be worse for existing assets than for new assets. The estimate of benefits from existing assets depends on assumptions about what would have happened in the past absent the investment, and not just about the future.*"

3.38 We agree that, if the AoB charge is applied to existing assets, it would be a challenging task to define the counterfactual scenario in which the investment did not take place. For

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34 R. H. Coase, 1946, *The Marginal Cost Controversy*, Economica, New Series, Vol.13, No.51, (Aug., 1946), pp169-182, at 179

35 For an explanation of why the economic loss is approximately proportional to the square of the tax rate see Creedy, J.(2009), The distortionary costs of taxation, at http://www.victoria.ac.nz/sacl/cagtr/twg/Publications/5-the-distortionary-costs-of-taxation-johncreedy.pdf and also see Creedy, J. (2003), The Excess Burden of Taxation and Why it (Approximately) Quadruples When the Tax Rate Doubles, New Zealand Treasury Working Paper 03/29, pp. 26, at http://www.treasury.govt.nz/publications/research-policy/wp/2003/03-29 .

36 Hogan, W. W. (2011).*Transmission Benefits and Cost Allocation*, *p.13*

example, it would be challenging to make reasonable assumptions about counterfactual generation, load and other transmission investments.

3.39 However, we consider that there may be potential ways to resolve this issue.

3.40 One approach might be to adopt a simplified beneficiaries-pay approach for existing assets. That is, costs could be allocated for existing assets in a manner that is *roughly* commensurate with benefit.[37] For example, an interconnector approach could be adopted, in which geographic zones are identified and assets are categorised as within-zone assets or interconnecting assets, and rules are determined to allocate interconnecting assets between customers located in the various zones. These rules could be simple and deterministic. For example, the costs of an interconnector could be borne 50% by load customers in the importing zone (or zones) and 50% by generators in the exporting zone. Such an approach may be feasible for New Zealand's stringy grid, where the predominant pattern of flow on the backbone grid is predictable, even if it is not feasible in the "sufficiently dense network" referred to in the quotation from Professor Hogan's work above.[38] We would note that this approach has not been explored in depth; it is noted here as a possible example of an approach to cost allocation that is roughly commensurate with benefit.

3.41 Another approach might be to apply the AoB charge to the limited subset of substantial transmission network investments made in New Zealand in the last 15 years. Given that these investments are recent, and that high-quality data exists in respect of these investments, it may be relatively straightforward to define a counterfactual scenario for these investments (by comparison with other assets). If so, then from a technical and analytical standpoint, implementing an AoB charge for a limited subset of investments, might not add much complexity to implementation. This is discussed further in section 4.

Implementation costs would be higher

3.42 Determining the future benefits that participants will receive from an investment is potentially a complex exercise and so allocating costs via the AoB charge would have higher implementation costs compared to allocating costs according to an easily measureable metric such as peak demand or anytime maximum demand. (On the other hand, calculating the allocation for the AoB charge is a one-off exercise, but allocating via peak demand as under the status quo or on an ongoing basis, would incur ongoing operational costs.)

3.43 Applying the AoB charge to existing assets (in addition to future investments) would involve higher implementation costs compared to a future-only implementation, because it requires the calculation of benefits for a greater number of investments. Also, there is less information available about the cost of historic investments.

3.44 In addition, because the amount of money allocated under the TPM is so large, implementation of the TPM is likely to involve significant resource costs in the form of submissions, expert advice, legal action, lobbying and uncertainty.

3.45 Applying the AoB charge to existing assets would involve higher resource costs of this nature compared to a future-only implementation. This is because applying the AoB

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37 We think a simple approach is all that is required to calculate benefits for existing assets. By contrast, a more sophisticated approach can be more efficient when the beneficiaries-pay approach is applied to future investments, because transmission customers' private benefits will be better aligned with overall societal benefit if the benefit-based allocation of the costs of future investments is more accurate.

38 Hogan, W. W. (2011).*Transmission Benefits and Cost Allocation*, *p.13*

charge to existing assets involves significant wealth transfers between customers (it would significantly increase some parties' transmission charges whilst significantly decreasing others).[39] This is likely to encourage parties facing increased transmission charges to undertake legal action and lobbying.

Some stakeholders argue that it would undermine regulatory certainty (but we don't agree)

3.46 It could be argued that applying the AoB charge to existing assets would undermine regulatory certainty, because it represents an unanticipated change to a settled set of arrangements (or "regulatory bargain") on the basis of which some parties have made investments. If so, this could increase the cost of capital in future, and so undermine dynamic efficiency. Proponents of such arguments typically argue that where there is a change to existing regulatory arrangements, the new rules should apply only to future investments; while existing investments should remain subject to the existing rules.

3.47 However, there are strong counter-arguments.

3.48 The default expectation, in New Zealand at least, should be that inefficient regulatory arrangements will not remain settled. Rather, it is to be expected that such arrangements will not survive. Successive Governments in New Zealand since the mid-1980s have sought to reform inefficient regulatory arrangements.

3.49 Further, the standard approach in New Zealand is that changes to existing regulations are applied equally to both future investments and existing investments. There are many examples of legislation and regulation (e.g., tax, pollution regulation) that have been introduced without any need for "carve-outs" for businesses that have made investments in reliance on the old rules.

3.50 This standard approach, under which existing investments are treated no differently to future investments, is consistent with public expectations. This was illustrated in a recent hearing of the Regulations Review Committee of Parliament, in which a challenge to one of the Authority's recent regulatory decisions was considered. The Authority decided in 2016 to amend an existing regulation relating to distributed generation. One of the effects of the decision was that the owners of some existing distributed generation would no longer be entitled to receive a payment that they had previously received each year. Much of the challenge to the decision consisted of arguments that the regulatory change should apply only to future investments and not to existing investments. The Regulations Review Committee did not place any weight on these arguments.

3.51 A further example comes from the Authority's approach in its concurrent review of distribution network pricing. In that context, the Authority has called for an industry-led approach to reform of distribution prices on a service-based and cost-reflective basis. In that context, while the Authority has made no final decisions, there has been no suggestion that pricing changes would not be applied to existing assets. None of the Authority's stakeholders has raised any argument that charges for existing distribution assets should continue to be determined on the current basis. This is further support for the view that there is no general expectation in New Zealand that existing investments will be exempted from changes to regulation.

3.52 Second, the Authority's statutory objective requires it to promote efficient market design for the electricity industry. If the Authority were to retain a set of arrangements (or policy)

[39] Wealth transfers are discussed in section 4.

that was inefficient, on the grounds that a more efficient policy would create uncertainty for those that invested to benefit from the inefficiency, this would encourage and reward rent-seeking behaviour. Requiring the ongoing retention of such policies would also penalise those who had correctly realised the policy would not survive an efficiency review a regulator must inevitably conduct, given statutory objectives. Such action by a regulator would discourage others from acting efficiently in future. Our conclusion is that the best way to promote regulatory predictability and the right climate for investment in the long-term is for the Authority to consistently pursue its statutory objective without fear or favour.

3.53 Regulatory changes can potentially affect the cost of capital. It's important to take a balanced perspective on these potential effects. We don’t consider that applying the AoB charge to existing investments is likely to have an upward impact on the cost of capital. However, even if it did have such an effect, it is important to be aware of potentially offsetting dynamic efficiency effects that would reduce the cost of capital. That is, one effect of the Authority adopting the most efficient policy it can identify is that a forward-looking investor can be more confident the Authority won't apply a less efficient policy in the future when dealing with other contentious issues. This might avoid future costs for the forward-looking investor, and so reduce their cost of capital. Our view is that the latter effect dominates. That is, the cost of capital will be reduced if the regulator consistently pursues its statutory objective, instead of refraining from making changes in order to uphold regulatory bargains it or its predecessors are claimed to have made.

3.54 In any case, the premise of the initial argument is incorrect: application of a beneficiaries-pay approach to existing assets is not an unanticipated change to a settled set of arrangements. Rather, industry stakeholders have been aware since 2004 (if not earlier) of the real possibility that beneficiaries-pay or some other form of “targeted” (i.e. not socialised) transmission charges would be applied in future, for existing assets as well as future investments. This matter is discussed further in Appendix D.

4 Applying beneficiaries-pay to all existing network assets or to a subset

4.1 In its 2016 proposal, the Authority also proposed, in addition to applying the AoB charge to future grid investments, to apply the AoB charge to a selected set of high-value historical investments (and potentially to all existing interconnected grid assets).

4.2 In this section we discuss whether, if the beneficiaries-pay approach is to be applied to existing assets (in addition to future investments), it should be applied just to a subset of existing assets or to all existing assets.[40] We set out the arguments for each approach.

Reasons to restrict to a subset of assets	**Reasons to extend to all existing assets**
High quality data is available for most of the 11 investments	Reducing distortion to location decisions
Estimation of benefits for the 11 investments is not analytically complex	Incremental improvements in efficiency

4.3 Our current view is that, if the AoB charge is to be applied to existing investments, it should be applied to the 11 selected existing investments that were identified in the 2016 proposal. These are the investments for which it is most feasible to implement an AoB charge, given their (in most cases) recent vintage and the existence of high-quality data. It is likely to be more difficult to implement AoB charges for other existing assets, and so would involve considerable implementation risk. We do not think that the cost allocation methodologies deployed by US independent system operators could be used in the same way to allocate costs for all existing investments. Furthermore, implementing the AoB charge to existing assets other than the 11 would mean that it would be unlikely to be implemented quickly, delaying the delivery of the main benefits from reforming the TPM.

4.4 This view might be different if the beneficiaries-pay approach could be implemented in an alternative, simpler way for other existing assets, such as an interconnector approach. These matters require further consideration and are beyond the scope of this paper.

4.5 We note that application of the AoB charge to future investments and the 11 investments identified in the 2016 proposal would involve applying two different charging regimes at the same time. In theory, this could raise durability issues similar to those discussed in section 3, as some regions would be required to pay for investments covered by the AoB charge, while continuing to pay part of the costs of previous investments from which they do not benefit (through the residual charge, which is socialised). We don't think this would have as much of an impact on durability as a future-only application, because the amount of cost remaining to be recovered through the socialised residual would be relatively low.

[40] A potential beneficiaries-pay approach could be applied to:

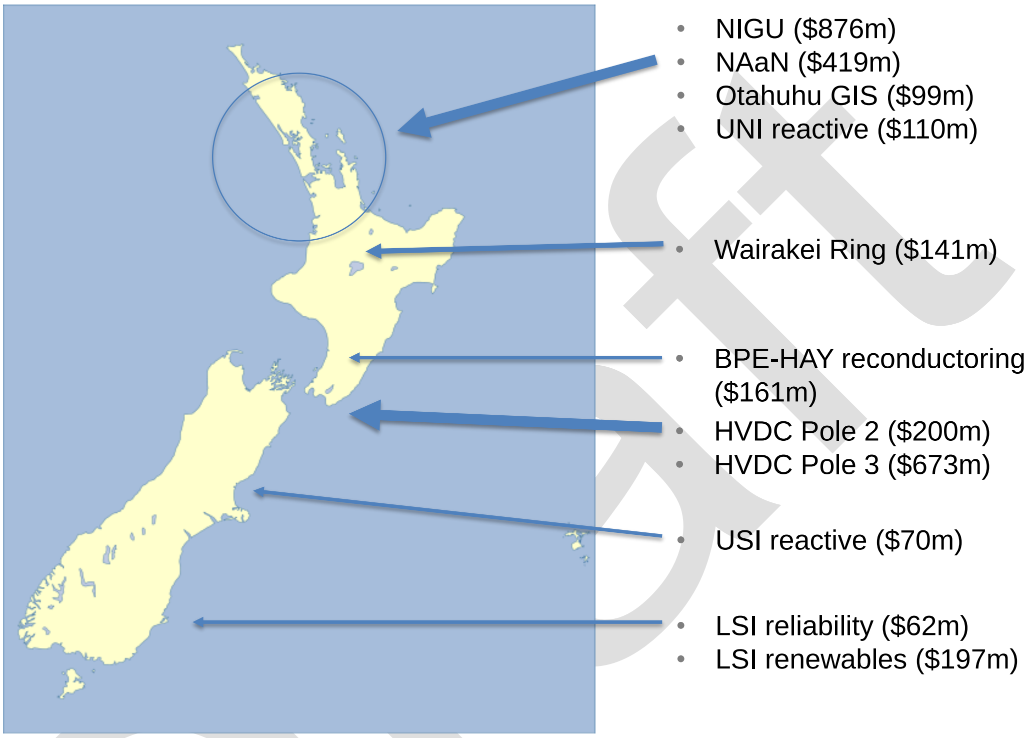
1. future investments and major investments made since 2004
2. future investments and the HVDC assets
3. future investments and the 11 existing investments that were identified in the 2016 proposal (i.e., both major investments made since 2004 and the HVDC assets).

Proposed application of AoB charge to existing assets

4.6 In the 2016 proposal, the AoB charge was intended to apply to assets in all future interconnected grid investments and to 11 selected historic investments.

4.7 The 11 historical investments to which the AoB charge would have applied under the 2016 proposal are shown on the map below. [41] The investments are to some extent geographically concentrated in the upper North Island (with some notable exceptions, such as the HVDC inter-island link).

11 historical investments identified in the 2016 proposal as eligible for AoB charge



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4.8 Ten of those existing investments were selected on the basis that they were approved after May 2004, and had a value of more than NZ$50 million at the time of commissioning. These approved assets were all commissioned in the years since 2011.

41 The 11 historical investments to which the AoB charge would have applied were:

(i) the North Island Grid Upgrade (NIGU) Project

(ii) the Upper South Island Dynamic Reactive Support Project

(iii) the Otahuhu Substation Diversity Project

(iv) Pole 2 of the HVDC link

(v) Pole 3 of the HVDC link

(vi) the Wairakei Ring Project

(vii) the North Auckland and Northland (NAaN) Project

(viii) the Upper North Island Dynamic Reactive Support Project

(ix) the Lower South Island Renewables Project

(x) the Lower South Island Reliability Project

(xi) The Bunnythorpe-Haywards Reconductoring Project

The 11th was a major component of the HVDC link (known as "Pole 2"), which was commissioned in 1992.

4.9 The rationale for the 2004 threshold and the NZ$50 million threshold was that the intended efficiency gains from charging for historical assets (discussed in section 3) need to be traded-off against the additional costs of applying the AoB charge to historical assets. The NZ$50 million threshold would limit the application of the charge to assets within a relatively small number of investments, which would reduce implementation costs compared with applying the charge to, for example, all historical assets approved since May 2004. However, the NZ$50 million threshold still captures the bulk of the total value of existing assets that have been approved since May 2004 (which was considered important for reasons discussed below).

4.10 The major (pre-2004) component of the HVDC link known as "Pole 2" was included in the list of eligible investments so that all charges for the HVDC would be service-based and cost-reflective, so that both HVDC poles (Pole 2 and Pole 3) would be charged for on a consistent AoB basis, and because the Authority considered the inclusion of Pole 2 was important to promote durability.

4.11 The Authority also provided the opportunity for the AoB charge to extend beyond the 11 identified investments and apply to all existing grid assets. The 2016 proposal allowed Transpower the opportunity to propose application of the AoB charge to all existing grid assets if and only if to do so could be demonstrated to be feasible and to promote the Authority's statutory objective. This potential application of the AoB charge to the whole grid was called an "additional component" of the Authority's proposal.

Wealth transfers resulting

4.12 Wealth transfers are not a relevant factor for the Authority's decision making, except to the extent they result in effects on efficiency. For example, if the Authority took the view that the proposal would be more or less durable as a result of wealth transfers. This could be a potential efficiency effect to be taken into account.

4.13 For the purposes of context only, we note that applying the AoB charge to the 11 historical investments listed in the Authority's 2016 proposal would create wealth transfers. For example, we estimate that, as a result of the proposal as a whole, the Auckland distributor Vector's charges would rise by around NZ$69 million per annum (assuming there was no price cap applied) and charges for Northland distributors Northpower and Top Energy would also rise substantially.[42] Regarding wealth gains, the aluminium smelter's charges would be expected to fall by NZ$21 million per annum, the South Island major generator Meridian Energy's by NZ$40 million per annum and major generator Contact Energy's by NZ$10 million per annum.

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42 Indicative modelling carried out by the Authority for the 2016 TPM proposal indicated Vector, Northpower and Top Energy were major beneficiaries of recent major transmission investments in the upper North Island, such as the North Island Grid Upgrade (NIGU), which cost $894 million. These recent major investments were proposed to be recovered through the AoB charge, and so charges for those networks would increase, reflecting the benefits they receive from these investments. The NIGU provides the upper North Island with considerable benefits, both in terms of access to lower electricity prices and improved reliability. The benefits that NIGU provides have increased even further in recent times with the closure of the Southdown and Otahuhu power stations. Note that these estimates are sensitive to various assumptions including for example the approach to valuation of assets subject to the AoB charge.

Advantages of restricting the AoB charge to a subset of existing assets

High quality data is available

4.14 High-quality data is available on the 10 of the 11 substantial post-2004 transmission network investments, making it more feasible to estimate the benefits likely to flow to the various parties from these investments (compared to other existing assets). This is because these 10 investments were approved under the Commerce Commission's regulatory regime. This process required Transpower to provide demand forecasts and other data that would be useful in estimating the benefits likely to flow to the various parties from each investment. This regulatory regime did not apply to transmission investments approved before 2004.

4.15 The data available with respect to other existing assets is of lower quality and less complete.

Estimation of benefits for the 11 investments is not analytically complex

4.16 Given that 10 of the 11 investments are of recent vintage (commissioned in the years since 2011), and that high-quality data exists in respect of these 10 investments, it may be relatively straightforward to define a counterfactual scenario for these investments (by comparison with other assets). If so, then from a technical and analytical standpoint, implementing an AoB charge for a limited subset of investments, might not add much complexity to implementation. The complexity could potentially be further reduced by aggregating the 10 recent investments into groups.

4.17 The remaining investment of the 11 is the older of the two components of the HVDC link (Pole 2), which was commissioned in 1992. However, we consider that estimating benefits for the two HVDC investments (Poles 2 and 3) is reasonably tractable. This is because they can be treated sequentially (i.e., first assess benefits for Pole 3 with Pole 2 in place and then assess the benefits of Pole 2 without Pole 3 in place). The Authority has carried out analysis in the past to estimate and assign the benefits of the HVDC assets using a version of the market clearing model.

4.18 By contrast, it would be more difficult to define the counterfactual scenario (and so estimate benefits) with respect to other existing assets. We are aware that a number of independent system operators (ISOs) in the US (including the New York ISO, the Midcontinent ISO and PJM) take a beneficiaries-pay approach to cost allocation for future transmission investments. However, we do not think that the cost allocation methodologies deployed by these ISOs could be used in the same way to allocate costs for all existing investments. The ISOs invest considerable resources in defining an agreed base case (counterfactual scenario) for future demand and generation, and then consider the effects of a proposed investment by reference to that base case. While this approach might be applied to recent, major investments, it would be impractical to extend it to all existing assets, given their greater age and lack of high-quality data.

4.19 We might reach a different conclusion if the beneficiaries-pay approach could be implemented in an alternative, simpler way for other existing assets (such as the interconnector approach discussed in section 3). We are separately considering the question of whether benefits can or should be estimated for existing assets on a whole-of-grid basis, as opposed to an investment-by-investment or interconnector approach. These matters require further consideration and are beyond the scope of this paper.

Advantages of extending the AoB charge to all existing assets

Reducing distortion to location decisions

4.20 As noted in section 3, if an AoB charge applies in some locations but not in others, this could discourage generators, and potentially industrial load customers, from connecting to the grid in a location where an AoB charge would apply.

4.21 If the AoB charge is applied to a subset of existing assets (such as the 11 investments identified in 2016), this approach would involve applying two different charging regimes at the same time: one for both future investment and the 11 investments identified in 2016, and another for all existing network assets. This might create inefficient incentives for investment in generation and potentially load.

4.22 This is because under this approach, a newly connecting party (generator or load customers) would pay AoB charges only if they choose to locate in an area where they would be identified as a beneficiary either of one of the 11 investments identified in 2016 or of a transmission investment that has been made since the cut-off date. The newly connecting party can avoid the AoB charge if it locates in an area that is served only by existing assets not subject to the AoB charge. We don't know how material this effect is.

4.23 This effect could be significantly reduced if the AoB charge were to be applied to all existing network assets (rather than a subset of existing asset such as the 11 investments identified in 2016). This is because in this scenario a customer cannot avoid paying an AoB charge no matter where it chooses to locate.

Incremental improvements in efficiency

4.24 As discussed in section 3, applying the AoB charge to existing network assets can:

(a) improve the efficiency of asset maintenance decisions

(b) improve the information transmission users have about the future transmission charges they are likely to face

(c) reduce the inefficiency resulting from a high residual charge.

4.25 These efficiencies would be greater if the AoB charge were to be applied to all existing network assets, rather than to a subset of existing asset such as the 11 investments identified in 2016. This is because in the case where the charge is applied to all existing assets:

(a) maintenance decisions on a greater number of assets are subject to the AoB charge

(b) cost information on a greater number of assets is available to transmission users

(c) a greater number of assets are subject to the AoB charge, so there is less cost remaining to be recovered through the residual charge.

Applying AoB charge to future investments and HVDC assets

4.26 In the above discussion in this section, we have considered arguments for and against applying the AoB charge to a subset of existing assets (in addition to future investments). In doing so we have focussed mainly on the 11 investments identified in the 2016 proposal. However, there is another option: to apply the AoB charge to the existing HVDC assets (in addition to future investments). Under this option the cost of the remaining existing assets would be recovered through a socialised residual charge.

4.27 This option would reduce the locational distortion to efficient investment incentives for South Island generation caused by the existing HVDC charge. (A key problem with the existing HVDC charge is that the full cost of the HVDC link is charged to South Island generators, and is regularly updated based on their injection into the system. This discourages investment in generation in the South Island relative to the North Island. This is an example of locational distortion.) This option would also improve the efficiency of investment and would eliminate inefficiency caused by the existing RCPD charge. However, this option could still result in location distortion caused by applying the AoB charge to some assets and not to others, as discussed earlier in this paper.

4.28 This option could also result in some additional efficiencies (which are similar to those discussed in section 3). It can improve the efficiency of asset maintenance decisions with respect to the HVDC assets, as they are covered by the AoB charge. It can also positively influence the efficiency of future investment decisions with respect to the HVDC, by improving the information available about the future transmission charges users are likely to face.

4.29 This option would cause some inefficiency resulting from a high residual charge (for the reasons discussed in section 3).

4.30 This option might involve some implementation difficulties, as it involves applying the AoB charge to existing assets (the HVDC assets). However, as noted earlier in this section, we consider that estimating benefits for the two HVDC investments (Poles 2 and 3) is likely to be reasonably tractable.

4.31 For the purpose of providing context only, we note this option is estimated to create a wealth transfer from North Island load to South Island generation of around $50m pa, as, under an AoB charge, North island load would bear some of the costs of the HVDC assets previously borne by South Island generation.

Appendix A Current rules for allocating the cost of transmission investments

A.1 The TPM allocates costs to designated transmission customers (transmission customers) for each pricing year. There are three TPM charges (connection, HVDC and interconnection) and a prudent discount policy.

TPM allocates costs to transmission customers for each pricing year

A.2 The TPM requires Transpower to determine for each pricing year the allocation of transmission charges among transmission customers. Those charges recover Transpower's revenue for that pricing year.[43]

A.3 Transmission customers are:

(a) connected asset owners, which include direct consumers (often called grid-connected consumers) and distributors (connected asset owners are often called "load" in this context)

(b) generators that are directly connected to the grid.

A.4 Transpower must charge for its transmission services in accordance with the TPM. The TPM is incorporated in transmission agreements between Transpower and each transmission customer, and charges payable are recoverable as a debt due to Transpower.

Connection charge

A.5 The connection charge recovers the costs of connection assets. These are dedicated alternating current assets connecting a distributor, direct consumer, and/or generator, to the transmission grid.[44] Connection charges were about NZ$128 million for the 2015/16 pricing year.

Charge is based on deep connection approach

A.6 The current TPM adopts a 'deep connection' approach to identifying assets that will be subject to the connection charge. This involves identifying the assets that exist to connect a party's electrical assets with the grid. The 'deep connection' approach is based on a physical definition of connection assets, whereby the key distinguishing feature is that there are no 'loop flow' effects on the assets, making it easy to identify beneficiaries of the asset.

A.7 Under the TPM, a connection charge is calculated for each connection asset. The TPM includes a method for apportioning charges for a connection asset if there is more than one customer for that asset. A customer's share of charges for a connection asset is the 'customer allocation'. Connection charges consist of an asset component, a

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[43] Transpower carries out this exercise in the period September to December of the year immediately before the pricing year.

[44] In most cases connection assets are used by a single transmission customer, but there are some cases where two or more transmission customers share connection assets. The TPM allocates the connection charge for shared connection assets at a connection location in proportion to each transmission customer's share of maximum injection or demand at the connection location.

maintenance component, an operating component and, for injection customers, an overhead component.[45]

Asset component

A.8 The asset component provides Transpower with a return on capital, and a return of capital, for connection pool assets. It allocates a portion of the cost of funding all connection assets plus their depreciation to the connection assets for which the charge is being calculated.

A.9 Under the current connection charge, the asset component is calculated on the basis of applying average depreciation to all connection pool assets. This approach effectively flattens connection pool charges across the life of each asset.

Maintenance, operating and overhead components

A.10 There are separate maintenance, operating and overhead components (operating expenses) of connection charges. At a high level, these charges are calculated using cost allocators rather than actual cost.

Asset valuation method

A.11 The TPM requires Transpower to use the replacement cost (RC) of connection assets in calculating several of the components of the connection charge.

A.12 The asset return rate used in calculating the asset component of the connection charge also requires Transpower to use the regulatory asset value of connection assets that is recorded in Transpower's asset register. This value is based on historical costs (i.e., the original cost of building the assets).

A.13 For assets commissioned before the date of the last ODV report published by Transpower before the current TPM came into force (the transition date), the replacement cost is the cost of replacing the relevant asset with a modern equivalent with the same service potential, multiplied by a replacement cost adjustment factor. The adjustment factor is the optimised replacement cost as at the transition date, divided by the cost of replacing that asset with the then-modern equivalent.[46]

A.14 For all other assets, the replacement cost is simply the cost of replacing the relevant asset with a modern equivalent with the same service potential.

HVDC charge

A.15 The HVDC charge recovers the cost of the high voltage direct current link between the North Island and the South Island (HVDC link). HVDC charges were about NZ$150 million for the 2015/16 pricing year.

A.16 Up until April 2017, HVDC charges were paid by South Island generators based on their share of peak injections in the South Island (historical anytime maximum injection or HAMI).[47]

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45 The connection charge for injection customers (generators) includes a share of overhead costs (i.e., indirect costs such as head office). Off-take customers (distributors and direct major users) are charged for overhead costs through the interconnection charge.

46 See definitions of optimised replacement cost, replacement cost, replacement cost adjustment factor, and transition date in the TPM.

47 HAMI for a customer at a South Island generation connection location currently means either the average of the 12 highest injections at that South Island generation connection location during the capacity measurement period for the relevant pricing year; or the average of the 12 highest injections at that South

A.17 The Authority recently approved an amendment to the TPM (i.e. just the methodology not the guidelines) that will replace the HAMI-based charge with a charge based on the total injection by each South Island generator at each South Island generation connection location, averaged over 5 years.[48] The new approach is called the South Island Mean Injection (SIMI) charge. The HAMI-based charge will be phased out (and the SIMI-based charge phased in) over a 4-year period which began on 1 April 2017.

Interconnection charge

A.18 The interconnection charge recovers all of Transpower's regulated revenue that is not recovered through the connection charge or HVDC charge. It is paid by distributors and direct consumers.

A.19 The interconnection charge recovers the cost of interconnection assets (i.e., the assets that are neither connection assets, nor the HVDC link) and a proportion of overhead and unallocated operating costs. Interconnection charges were about NZ$639 million for the 2015/16 pricing year.

A.20 The interconnection charge for a customer is based on the customer's demand during the N trading periods with the highest regional demand (regional peak demand periods). In recent years, N has been 12 for the Upper North Island and Upper South Island regions, and 100 for the Lower North Island and Lower South Island regions. The Authority has recently approved an amendment to the TPM (as a result of Transpower's operational review) changing N for all regions to 100 (this change is currently in the process of being phased in over a number of years).

Prudent discount policy

A.21 The TPM includes a prudent discount policy (PDP). The TPM states that the purpose of the PDP is to help ensure that the TPM does not provide incentives for uneconomic bypass of existing grid assets, and that the PDP aims to deter investment in alternative projects that would allow a customer to reduce its own transmission charges, while increasing economic costs to New Zealand as a whole.

A.22 In other words, the rationale for granting a prudent discount is that it would avoid large economic inefficiencies in situations that can be characterised as 'win-win'—i.e., granting the discount avoids a customer investing in an alternative project to bypass the existing grid, which avoids other transmission customers paying higher transmission charges and minimises total economic costs to the nation as a whole.

A.23 The PDP does this by discounting the charges for a party who would otherwise not connect to the transmission grid or would disconnect from the grid. The costs of agreed prudent discounts are recovered from other transmission customers in accordance with the TPM. However, if the alternative project was undertaken, those other customers would face even higher costs, namely increased transmission charges (because Transpower's revenue would have to be recovered from a smaller revenue base).

Island generation connection location during the four immediately preceding pricing years, whichever is highest.

48 This resulted from a proposal to amend the TPM that was put forward by Transpower in 2015. Transpower may propose an amendment to the TPM for the Authority's approval, provide it is consistent with, inter alia, the TPM guidelines and the Authority's statutory objective. Transpower would typically consult with stakeholders before making such a proposal. This process is known as an "Operational Review" of the TPM.

A.24 In order for a transmission customer to obtain a discount under the PDP, a transmission customer's alternative project must be (determined in accordance with the criteria in the PDP):

(a) technically, operationally and commercially viable and have a reasonable prospect of being able to be successfully implemented

(b) uneconomic to implement given Transpower's economic costs of providing existing grid assets and the economic costs that would be incurred by the customer if it proceeded with the alternative project.

A.25 Transpower currently has three prudent discount agreements in place.[49] All three agreements treat generation capacity that is directly connected to Transpower's grid as though the generators were physically embedded. Prior to 2008, a number of notional embedding agreements, the precursor to prudent discount agreements, were signed and several of these are still operative.

[49] The Matahina and Aniwhenua Prudent Discount Agreement (2014), the Southdown Prudent Discount Agreement (2012) and the Waipori Prudent Discount Agreement (2013). The Authority notes from information provided by Transpower that a number of current prudent discount agreements (entered into under the arrangements for notional embedding arrangements) are due to expire in coming years; one is under current renegotiation.

Appendix B The Authority's interpretation of its statutory objective

Summary

B.1 The Authority interprets its statutory objective as requiring it to exercise its functions in section 16 of the empowering legislation the Electricity Industry Act (2010) in ways that, for the long-term benefit of electricity consumers:

(a) facilitate or encourage increased 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) encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst being robust to adverse events; and

(c) increase the efficiency of the electricity industry,[50] taking into account the transaction costs of market arrangements and the administration and compliance costs of regulation, and taking into account Commerce Act implications for the non-competitive parts of the electricity industry, particularly in regard to preserving efficient incentives for investment and innovation.[51]

Competition limb

B.2 In regard to competition the Authority notes that:

(a) consistent with the Commerce Act, the Authority interprets competition to mean workable or effective competition;

(b) facilitating or encouraging increased competition applies to both buyers and sellers in the markets for electricity and electricity-related services;

(c) the benefits of competition refer to efficiency benefits, not wealth transfers, arising from price movements, but it includes any efficiency effects that may arise from wealth transfers;

(d) efficient entry and exit in markets are not necessarily orderly; and

(e) workably competitive markets can bring very large benefits to consumers over the long term if they are conducive to entry by innovative suppliers and conducive to efficient investment.

Reliable supply limb

B.3 In regard to reliable supply the Authority notes that:

(a) both continuity of supply and quality of supply are of interest to the Authority, subject to the jurisdiction of the Commerce Act;

(b) it is currently not always possible to closely tailor security and reliability to the preferences of individual electricity consumers due to the shared nature of the

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50 The Authority interprets 'electricity industry' to include all parties involved in the electricity industry and not just 'industry participants' as defined in the Act.

51 The Commerce Act is the legislation under which the Commerce Commission determines the regulated revenue that Transpower and distributors are able to recover through regulated network charges.

electricity system, although the option should be preserved, where possible, for consumers to invest to achieve their individual preferences;

(c) although it is usually not possible to estimate the aggregate marginal benefit of security and reliability with a high degree of precision, broad estimates are available to set key parameters for security and reliability that are approximately efficient; and

(d) consumer concerns about security and reliability may not be constant over time, with concerns growing when events become proximate and receding when events pass.

Efficient operation limb

B.4 The Authority also notes that:

(a) efficient operation of the electricity industry covers situations not adequately covered by the competition and reliable supply aspects of the Authority's statutory objective;

(b) efficient operation of the electricity industry is interpreted within the context of other Government legislation and regulation affecting the electricity industry, and in particular does not allow consideration of pan-industry externalities such as carbon emissions; and

(c) in situations where it is considering initiatives that have conflicting effects within its statutory objective, the Authority will seek to make decisions consistent with maximising overall efficiency benefits for the long-term benefit of electricity consumers.

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Appendix C Inefficiencies of the current cost allocation rules for transmission services

C.1 At the time of its 2016 proposal, the Authority expressed the view that, in relation to the interconnection and HVDC charges, there were three main problems with the TPM:

(a) *Poor price signals are incentivising inefficient use of the interconnected grid, inefficient levels of grid investment, and inefficient investment by grid users.*

Charges for the interconnected grid send poor price signals for use of the interconnected grid, which affects a wide range of investment decisions.

(b) *Poor price signals are causing inefficient participation in decision-making in regard to the interconnected grid, which leads to inefficient grid investment decisions*.

(i) Participants face incentives to pursue grid investments that provide net private benefits to those benefiting from the investment, but are not efficient overall. This arises because the current charges mean they either contribute little to the cost of the investment compared with the benefit received, or do not have to contribute to it.

(ii) Participants do not face incentives to participate in ways that support the discovery of efficient transmission investment options (including alternatives to transmission) through the transmission investment approval process.

(c) *The current TPM is not durable.*

The interconnection and HVDC charges harm the durability of the current TPM. Poor durability exacerbates long-term uncertainties, potentially causing grid users to make inefficient location and investment decisions. It also results in resources being directed at lobbying for fundamental changes to the TPM that would not occur with a more efficient TPM.

C.2 Each of the above problems is discussed in more detail below.

Poor price signals are incentivising inefficient use of the interconnected grid, inefficient levels of grid investment, and inefficient investment by grid users

Poor cost-reflectivity in the interconnection and HVDC charges is causing inefficient use of the interconnected grid, with flow-on effects for inefficient use and investment by grid users to avoid using the grid

C.3 In the Authority's view, nodal pricing provides good price signals for parties to use the interconnected grid efficiently. This is not the case, however, for the price signals provided by the current TPM—indeed the current interconnection and HVDC charges counteract the price signals provided by the nodal spot market.

C.4 Under the current TPM, load customers are charged for interconnection assets based on their share of demand in the top 100 regional peak demand periods in a year in the region in which they are situated. A customer's demand in those periods is called its regional coincident peak demand or RCPD. South Island generators are charged for the HVDC based on averaged half-hour historical anytime maximum injections (HAMI), transitioning to a charge based on South Island mean injections (SIMI) over a 4-year period beginning from 1 April 2017.

C.5 For interconnection assets, the RCPD signal is poorly correlated with times when the grid is congested, which means the price can be high at times during the day when the marginal cost of using interconnection circuits is very low. Hence, the RCPD signal in the interconnection charge is not cost-reflective, encouraging load customers to forgo consumption or to operate expensive distributed generation (DG) plant to smooth peak demand in circumstances when lower peaks provide no economic benefit at all.

C.6 Likewise, the averaging component of the HAMI-based method for calculating HVDC charges means that the price signal for using the HVDC is not well correlated with the marginal cost of using the HVDC. Under the SIMI-based method for calculating HVDC charges, which also uses an averaging component, the cost of using the HVDC exceeds the marginal cost. Both the HAMI and SIMI-based methods for the HVDC charge send a price signal that, when combined with nodal price signals, inefficiently discourages use of the HVDC.

C.7 Also, under the interconnection charge, the rate of the interconnection charge is highest immediately after a grid expansion and lowest just before a new grid expansion is completed. This is completely the opposite to the trend for the marginal cost of the grid and the trend for nodal prices. Again, it encourages grid users to forgo consumption and/or operate expensive DG plant when there is plenty of spare capacity. A similar mismatch between the charge and the marginal cost occurs with the HAMI methodology for calculating the charge for the HVDC, and is likely to occur to some extent for the new SIMI method.

C.8 Some direct consumers, by reducing their consumption or installing and operating DG to avoid the 100 RCPD peaks, are not currently paying the variable cost of supplying interconnection services to them, such as maintenance costs. This is unequivocally inefficient because it means the direct consumer is not even covering the cost of resources spent on keeping such transmission assets operating. This is also not consistent with a cost-reflective charge.

C.9 Direct consumers are able to avoid paying interconnection charges by altering their production levels or through investing in DG to manage their peak demand for grid-supplied electricity. This activity is wasteful if it occurs when there is substantial spare grid capacity and therefore little if any supply cost to avoid. In these cases, costs will be shifted from these direct consumers to other consumers.

C.10 Such distortions in grid use are likely to waste real resources in terms of the operation of expensive generation plants and demand management when they're not really needed, and are likely to be encouraging further investment in DG, as well as affecting retirement and upgrade decisions. Since there are more than 160 power stations connected to local networks or embedded networks, these distortions in grid use are likely to be very costly.

Poor alignment of interconnection and HVDC charges with service-based pricing is also encouraging inefficient use of the interconnected grid, with flow-on effects for inefficient location of grid users around the grid

C.11 TPM charges should be structured to the greatest extent possible so they do not distort grid users' production and investment decisions. This occurs when all parties that receive services from a grid circuit collectively pay the full costs of the circuits (cost-reflectivity), and parties that do not receive any services are not required to pay for those circuits (service-based).

C.12 The HVDC charge, which is collectively paid for by South Island generators, is somewhat service-based because South Island generators receive net benefits from the service provided by the HVDC assets. It is not fully service-based because North Island consumers also receive net benefits from the HVDC asset but do not pay for it.

C.13 The interconnection charge is also not aligned well with a service-based charge. Generators clearly benefit from the services provided by interconnection assets, but do not pay interconnection charges. For example, recent upgrades to the Wairakei Ring in the central North Island were undertaken to remove export constraints to enable development of generation options in the region. Generators located there clearly receive a service level improvement, to their benefit, but they contribute nothing to the costs of the upgrade.

C.14 Similarly, if the aluminium smelter at Tiwai ceased operating, then the grid in the lower South Island would need to be augmented so that surplus power from the deep south could flow north.[52] However, under the current TPM, South Island generators would face none of the additional charges for those augmentations, even though the upgrade would clearly remove an export constraint for them.

C.15 A further example arises in regard to gas transmission versus electricity transmission. Currently, generators have to pay for the gas pipeline (access and usage charge) that transports the gas for their generation. This means gas-fired generators face strong incentives to build their plants in the Taranaki region (where most of New Zealand's gas wells are located) because they will pay zero charges for using interconnection assets to transport their electricity to a centre of consumption such as Auckland (and other parts of the grid). Building the gas-fired units in Taranaki is likely to be cheaper for the generator even if it is ultimately more costly to consumers than building in Auckland and using the gas pipeline.

C.16 Grid users are therefore encouraged to make inefficient locational decisions, leading to inefficient grid use that drives inefficient grid investment outcomes. There are around 60 power stations directly connected to the national grid, which means there have been many production and investment choices in the past that could potentially have been affected by interconnection costs not being charged to generators.

Inefficient use of the interconnected grid leads to inefficient investment in the interconnected grid and inefficient investment by grid users

C.17 Future decisions about investment in the interconnected grid will inherently be inefficient because poor price signals incentivise inefficient use of the interconnected grid.

C.18 Transpower seeks approval for major investments based on its forecasts of actual grid use, whether the investments are proposed for economic or reliability reasons.[53] Likewise, the Commerce Commission approves or declines Transpower's proposals based on its forecasts of grid use. Hence, if pricing signals incentivise inefficient use of the grid, then the proposed investments are likely to also be inefficient.

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52 The Tiwai point aluminium smelter is the largest electricity consumer in New Zealand, and consumes approximately 13% of total electricity generated nationwide.

53 'Economic investments' are investments for which the economic benefits from reducing transmission losses and constraints yield net electricity market benefits. 'Reliability investments' are investments for which the primary effect is that they reduce supply interruptions to consumers.

C.19 The Commerce Commission's impartiality, analytical rigour and professionalism cannot save it from approving grid investments that overall are inefficient. Indeed, the more accurate are their forecasts of any inefficient grid use, the more certain the investment will be inefficient (in an overall sense).

C.20 In the same way, users will base their investment decisions in part on what it will actually cost them to use the grid. If use of the grid is inefficient, it can be expected that users' decisions to invest in assets that make use of the grid will be inefficient.

Poor price signals are causing inefficient participation in decision-making in regard to the interconnected grid, leading to inefficient grid investment decisions

C.21 The key issue here is that the TPM is not sufficiently service-based or cost-reflective and so grid users have poor incentives to engage in the Commerce Commission's decision-making on grid investment, and poor incentives to reveal better grid investment options (including alternatives to transmission).

C.22 For example, if a distributor requires investment in its network and there is a reasonably good interconnected grid investment option that would provide the same service, the distributor is likely to prefer the grid option because it will only pay a fraction of the costs of the grid option, but would have to pay the full costs if the investment was on its own network.

C.23 The Commerce Commission can only approve transmission investments that are proposed to it. Although Transpower's business case for its proposals include a comprehensive analysis of options, covering both network and non-network options, it is unlikely Transpower would know about all options and possibilities. Given the example above, it is unlikely that the efficient distribution option would ever be proposed. The distributor's customers would not inform the Commerce Commission of this option even if they knew about it, because informing the Commerce Commission would be against their financial interest.

C.24 The gas versus electricity transmission issue discussed on the previous page (paragraph C.15) provides another useful example. Carrying on from that example, the gas generator has strong incentives to tell Transpower and the Commerce Commission that the electrical circuits bringing power from Taranaki to Auckland need to be upgraded if they become congested, even though the congestion partly results from locating the generator in Taranaki. Under the current TPM, distributors and industrial consumers throughout the country will pay for the circuit upgrades, even though they arose from the decision to locate the gas generation plant in Taranaki.

C.25 The Authority is also mindful that ideas for costly transmission investments can arise quickly and unexpectedly. Recently consumers in parts of Auckland have been petitioning for the undergrounding of all urban transmission lines. This is despite undergrounding often being 7 to 10 times more expensive than overhead lines. With the current interconnection charge spreading this cost over New Zealand, there is little incentive for those advocating for the investment to factor in its cost. This is much less likely to occur under a service-based TPM, as the parties wanting the grid upgrade would have to pay for it.

C.26 The prospect of future investment in transmission, generation and load, and thus the potential for material efficiency gains, has heightened in recent times due to a number of developments. These developments include:

(a) Transpower forecasting significant transmission investment (more than NZ$200 million per annum) out to 2025. Transpower has also identified potential major capex projects and noted potential requirements for substantial additional transmission investment, e.g., investments required if the aluminium smelter at Tiwai (located at the bottom of the South Island) point exits the market, to transport electricity north from major generators in the far south of the South Island.[54]

(b) The growing calls for undergrounding transmission lines and associated prospect of changes to town planning documents to require or facilitate it. Undergrounding a transmission lines is very expensive (ca 10x cost overhead lines) and does not usually result in an improvement in service levels.

(c) The potential for additional renewable generation to be added to the New Zealand electricity system, some of which could be distant from load, brought about by the falling costs of renewable generation (especially wind) and the focus of the new New Zealand Government on emissions reduction policies in the electricity and wider energy sector (e.g., the electrification of industrial process heat would likely require significant transmission investment).

(d) Technology changes. The impacts that technological changes occurring in the electricity sector will have on transmission investment are not yet clear. They could heighten or lessen the need for future investment. However, expeditiously introducing an AoB charge that applies to future assets would ensure that the efficiency gains from an AoB charge on new transmission investments could be captured.

The current TPM is not durable

C.27 The current TPM is not durable, as evidenced by the almost constant lobbying for fundamental changes to the TPM. This has been ongoing for more than a decade. Poor durability exacerbates long-term uncertainties, potentially causing grid users to make inefficient location and investment decisions and poor operating decisions. It leads to ongoing lobbying costs for changes to the TPM.

C.28 In our view, recent technology developments reinforce the view that the current TPM guidelines are not durable. For example, expected reductions in the prices of large-scale batteries will make it profitable in the near future for parties to install batteries to manipulate demand to avoid transmission charges.

[54] The Tiwai point aluminium smelter is the largest electricity consumer in New Zealand, and consumes approximately 13% of total electricity generated nationwide.

Appendix D Stakeholders’ exposure to the possibility of beneficiaries paying for existing assets

D.1 This appendix provides information to support the following points:

(a) Changes to TPM charges on existing assets have occurred regularly throughout the TPM’s life, since the first TPM was introduced in 1989.

(b) Beneficiaries’-pays has been signalled as a possibility since 2004 (perhaps earlier), and in advance of the 11 eligible investments being proposed.

(c) Whereas the 2008 TPM (current TPM) was a final decision, the Electricity Commission advised that would immediately review the TPM post 2008, to determine the case for locational pricing.

D.2 Due to the above, it might be concluded that parties to the TPM were aware that beneficiaries-pay or some other form of targeted charges would be applied sometime in the future, for future and existing investments.

Changes to TPM charges on existing assets have occurred regularly during its life[55]

D.3 From 1988 to 1996, there was a gradual unbundling of the bulk supply tariff (BST) into energy and transmission components. The initial TPM contained connection, and demand (network capacity, transmission service and support system) charge components.

D.4 In 1996, several TPM changes were put in place. These included a move to optimised replacement cost, and a separation of HVAC and HVDC assets with revised charges under each. Transpower provided the following reason for the changes: “*to change what was largely an asset cost-based pricing regime to one that over time would become more service focused and more responsive to individual customer requirements*”.

D.5 In 1999, an Interconnection charge (allocated to offtake customers by peak demand ($/kW)) was introduced, which replaced the Access and Transport (which allocated 50% of the AC grid assets using a load flow model) charges. HVDC costs were South Island generators only, allocated by peak injection.

D.6 In 2008, the existing TPM came into force. The costs of interconnection assets were allocated to offtake customers by using their average regional coincident peak demand (RCPD), with the intention that it provide a price signal. HVDC charges continued to apply to South Island generators.

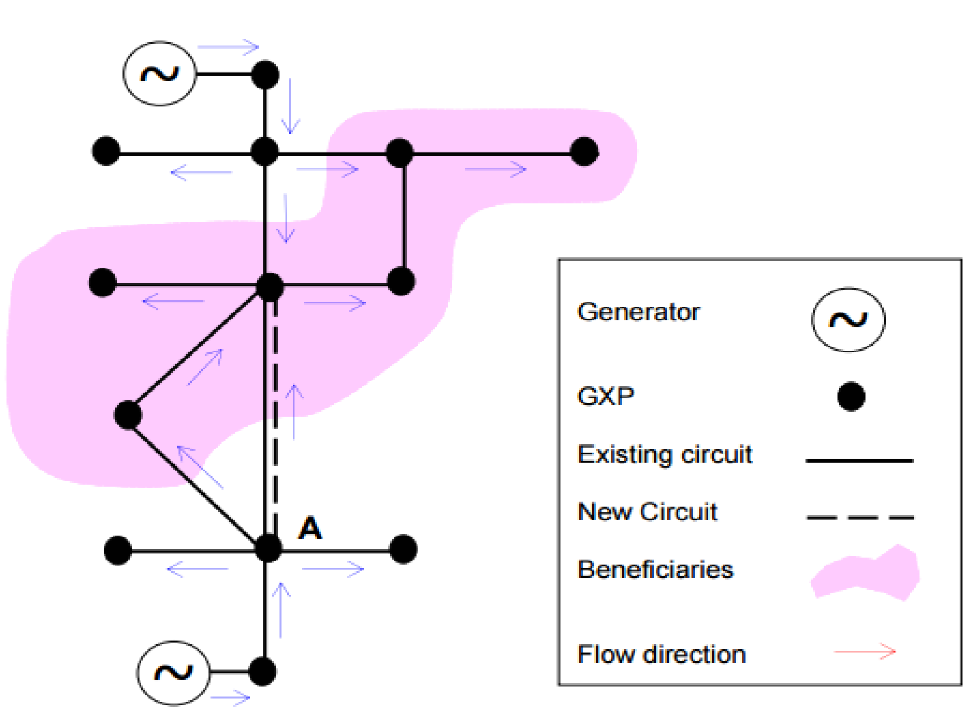
D.7 Conclusion: Transpower undertook three major revisions to the TPM between 1996 and 2008, which all applied to existing assets. Accordingly, the Electricity Commission created a precedent for changing TPM charges on existing assets.

55 Source: Report on the history of the Bulk Supply Tariff and Transmission Pricing in New Zealand, Strata Energy Consulting, prepared for Trustpower, January 2014.

Beneficiaries-pay has been signalled as a possible solution to problems with the TPM since 2004

D.8 Note the following beneficiaries-pay illustration was included in a TPM issues paper in 2004.[56]

Figure 3 – Identifying beneficiaries



D.9 Following publication of a 2004 issues paper, the relative efficiencies of beneficiaries-pay (and locational pricing) versus postage stamp charges were widely debated by industry participants.

D.10 In approving the current TPM guidelines in 2008, the Electricity Commission noted:

"*The amount of time and resources available to develop and implement a location-based signal meant that practical considerations and the desirability of consistency and certainty (both of which the Commission is required to take into account pursuant to rule 3.1) dictated that it preferred postage stamp charges until further work to investigate location-based transmission charges could be undertaken.*"[57]

D.11 The Commission accepted that the main beneficiaries of the HVDC link were South Island (SI) generation plant and North Island (NI) consumers. However, the Commission considered that beneficiaries were widespread but "not all will face strong incentives to identify least cost investment options if they are paying for new and replacement investments in the HVDC Link."

56 Electricity Commission, Issues paper: transmission pricing methodology guidelines, Sept 2004.

57 Electricity Commission, Statement of Reasons, paragraphs 54, 57, 78, paragraphs 80(e), 123, 126 and 143).

D.12 The Commission concluded that there "*were efficiency gains from improving location decisions of generators and avoiding other inefficiencies on consumer behaviour*…[and that], *efficiency is enhanced if SI generators, rather than NI consumers, face the costs of the HVDC Link*."

D.13 The Commission noted that "*The proper application of the [grid investment test] GIT should ensure welfare-enhancing transmission investments will take place, because the Commission is charged with approving investments which provide the highest net market benefits overall. The Commission considers that if the investment satisfies the GIT, the private benefits to SI generators will be far in excess of the cost of the investment because of the wealth transfers to SI generators which cannot be taken into account in the GIT.*"

D.14 As an aside, the Commission noted:

"The Commission considers that postage stamp charges for interconnection assets do not conform strictly to the principles of 'user pays', in that, whilst they charge users on the basis of the demand they place on the grid, they do not attempt to charge for a notional distance over which the electricity has been conveyed to a particular user. However, in terms of the overall pricing structure in option 1 of the consultation paper, which includes nodal pricing and deep connection charges, the extent of the departure from the 'user pays' approach depends on the effectiveness and degree with which nodal pricing and deep connection charges provide location and demand management signals."

D.15 Conclusion: Beneficiaries-pay was signalled to industry participants since at least 2004, before approval of the 11 eligible investments. The Commission's decision to charge only a subset of beneficiaries for the HVDC link rested on an assumption that NI load customers would not act on a price signal. If this assumption no longer holds (for instance, due to NI load customers having an increasing number of transmission alternatives or non-transmission solutions to consider), then it might be concluded that North Island consumers and other beneficiaries should pay a portion of the HVDC charge.

TPM review announced to consider locational pricing before current TPM was implemented

D.16 The current TPM become effective on 1 April 2008. In its final decision paper on the current TPM in 2007, the Electricity Commission noted that there was some support for a "but for"[58] approach, but that it was "difficult in practice to consistently apply [the but-for approach] over the entire grid." [59]

D.17 The Commission further noted:

"However, the Commission does agree that the "but for" approach, should be considered as part of a holistic review of the TPM focusing on locational pricing and it proposes to include such a review in its future work programmes. The Commission envisages that the review will be comprehensive and will be conducted through a formal structure."[60]

58 A "but-for" approach relates to "causers'-pay" and is a proxy for beneficiaries'-pay.

59 Electricity Commission, *Transmission pricing methodology: Final decision paper*, 7 June 2007.

60 Ibid, para 3.3.9, pg.17.

D.18 The Commission also noted that the TPM guidelines, which did not give effect to locational pricing, were final and must be followed in developing a new TPM.

D.19 Conclusion: In advance of the current TPM being developed by Transpower, and at the time the 11 eligible investments were being proposed, the Electricity Commission had advised the industry that a TPM review would be undertaken to assess whether targeted charges should be developed. It may be argued that industry participants should have been aware that beneficiaries-pay arrangements would be in place by the time the 11 eligible investments were commissioned.