Transmission pricing methodology: issues and proposal

Second issues paper

17 May 2016

Executive summary

Introduction

1. The Electricity Authority (Authority) is reviewing the guidelines that Transpower and the Authority must follow in setting the transmission pricing methodology (TPM). The TPM sets out how the revenue Transpower is entitled to recover in respect of the regulated components of the grid is allocated between designated transmission customers (the parties liable to pay the charges calculated under the TPM).

2. Currently, Transpower's annual revenue for the regulated parts of the grid amounts to $916.6 million per annum and will increase to close to $977.4 million per annum in 2019/20.[1]

3. The Authority considers that a revision to the current TPM may better promote the Authority's statutory objective in section 15 of the Electricity Industry Act (Act) of promoting competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.

4. Specifically, the Authority considers that improvements to the TPM could better promote efficient investment in transmission and other electricity assets, and the efficient operation of the electricity industry. This has the potential to deliver substantial long-term benefits to consumers.

5. In June 2015, the Authority released a TPM options working paper for consultation. This proposed three options for a TPM,[2] each of which included a number of charging elements. A key theme to emerge from the submissions on that paper was that the Authority was adopting too purist an approach which would result in undue complexity and in unintended consequences. In response to this feedback the Authority has proposed a simpler proposal consisting of fewer charging elements that incorporate a number of pragmatic judgements.

6. Further, the recently released consultation paper on distribution pricing[3] draws on a very similar decision-making and economic framework as that presented in this paper for transmission pricing. The Authority believes that evolving technologies are exacerbating the adverse effects of current approaches to distribution pricing, and that distributors need to alter their pricing approaches to be consistent with the Authority's statutory objective.

7. Evolving technologies are also opening up opportunities to use more sophisticated, accurate and efficient mechanisms to recover the costs of transmission assets. In particular, advances in computing power and algorithms over the last couple of decades makes it far more feasible to use sophisticated

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1 Commerce Commission, Companion Paper to the Update of Transpower's Maximum Allowable Revenues for the 2015/16 to 2019/20 Pricing Years, Table 3.1, page 8.

2 Transmission pricing methodology review: TPM options: Working paper, 16 June 2015, available at: https://www.ea.govt.nz/dmsdocument/19472.

3 Implications of evolving technologies for pricing of distribution services, 3 November 2015, available at: https://www.ea.govt.nz/dmsdocument/20057.

methods for measuring transmission services and identifying who receives those services.

8. As required under clauses 12.81 and 12.82 of the Electricity Industry Participation Code 2010 (Code), this paper discusses the process for development and approval of the TPM as well as guidelines for Transpower to follow in preparing the TPM.

9. While the Authority has included a few specific questions for submitters, the Authority also seeks feedback on all aspects of this paper.

A snapshot of the Authority's proposal

10. The Authority is proposing to replace two charges in the current TPM with two new main charges—an area-of-benefit charge on generation and load and a capacity-based 'postage stamp' residual charge on load customers only.

11. The Authority is proposing the area-of-benefit charge so that the parties that benefit from access to transmission services pay for those services, at a level that reflects the cost of providing those services.

12. The connection and area-of-benefit charges, along with nodal pricing in the spot electricity market, will provide price signals for efficient grid use and efficient investment decisions. Consequently, the residual charge is designed to collect the required revenue with minimum impact on grid use and investment decisions.

13. The area-of-benefit charge, combined with nodal pricing, will provide incentives for electricity distributors and industrial consumers to manage peak demand on the grid when and where it matters—ie, the nodal pricing spot market provides the incentives when grid constraints bind with increasing frequency, and the area-of-benefit charge provides incentives when the chances of grid upgrades increase due to deteriorating reliability or due to grid constraints binding more often and for longer durations.

14. Industrial consumers in the affected parts of the grid will be able to anticipate that new investments will increase their area-of-benefit charges and will want to take action to defer those investments if those actions are cheaper than higher nodal prices (until the investment occurs), and cheaper than their share of the cost of the new grid investment once it occurs.

15. Another key feature of the proposal is a widening of the current prudent discount policy (PDP). Subject to certain criteria, this will allow

    (a) load customers to apply for prudent discounts on their transmission charges, if standalone generation is a cheaper option for them

    (b) direct consumers to apply for a prudent discount if their transmission charges are creating a material risk that they will have to close down their New Zealand plant and disconnect from the transmission or distribution system.

16. The proposed expansion of the PDP is intended to reduce the risk of the 'postage stamp' residual charge driving large industrial consumers to close down and disconnect from the grid. It should also encourage distributors to use the transmission assets already serving them, rather than invest in local generation, if that would be a waste of resources for consumers.

17. Both of these effects can cause significant economic inefficiency (ie, poor outcomes for the economy, which would be detrimental to consumers) because the residual charge—being spread across all load customers—has little relationship to the services each customer receives from the transmission system or the incremental costs they impose on the transmission system. These concerns will decline over the long term as grid services transfer out of the residual and into the area-of-benefit charge.

18. Distributors and large industrial consumers will need to read the details regarding the new scope of the PDP to determine the likely impact on them. Overall though, if good decisions are made, allowing a wider range of circumstances to be eligible for prudent discounts should produce 'win-win' outcomes as it will avoid higher charges on other transmission customers, including residential consumers.

19. The Authority is also proposing to allow transmission customers to request Transpower to reduce the value of "area-of-benefit assets" if there has been a material reduction in the use of the assets. This process is often called optimisation.

20. The proposal to allow optimisation for area-of-benefit assets is intended to make the charge *market-like*—ie, 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 area-of-benefit charge without optimisation.

21. 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 area-of-benefit charges if the demand hasn't eventuated. As Transpower's total revenue is pre-determined by the Commerce Commission's price control regime, any optimisation of area-of-benefit charges will result in higher residual charges for all load customers.

22. In practice, optimisation is likely to be particularly relevant for remote and lightly populated areas of the country due to the sizeable impact that just a few large firms can have on the demand for local transmission services. But in principle optimisation could equally occur for other regions such has the central North Island (eg, the Tokoroa or Kawerau areas) where one or two industrial plants have a big impact on the demand for local transmission services.

23. We are also proposing other potential changes to the TPM, outlined later in this summary, including relatively minor changes to the connection charge in the current TPM.

24. In another paper released at the same time as this paper—called the *Distributed generation pricing principles (DGPP) consultation paper*—we are proposing to change the pricing arrangements for electricity generators connected to a local distribution network (known as distributed generation). The purpose of these changes is to encourage pricing arrangements for distributed generation that promote the long term benefit of consumers.

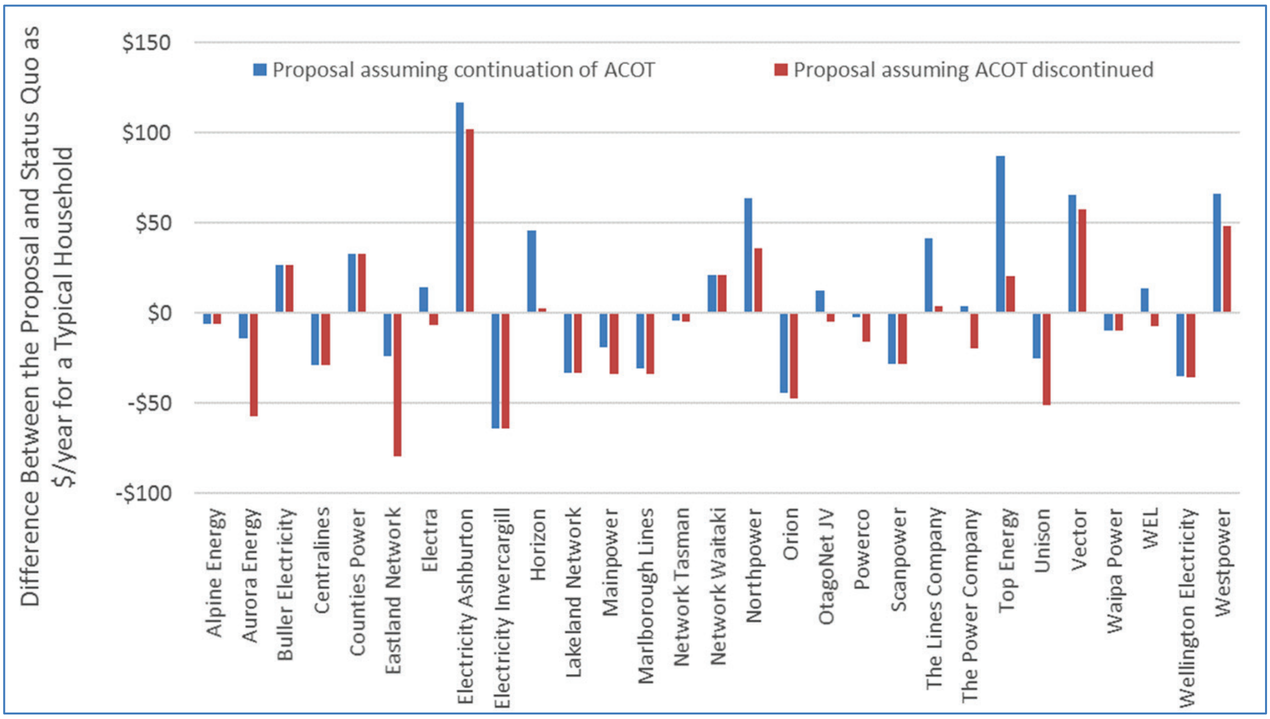
25. The proposed changes to the TPM, particularly the proposed shift from the current interconnection charge (described further below) to an area-of-benefit charge and a capacity-based residual charge, have the potential to substantially affect payments to distributed generation. On the other hand, as the DGPP consultation paper is proposing to alter the pricing arrangements for distributed generation anyway the net impact of the TPM proposals on distributed generation is likely to be reduced substantially.

The overall impact on residential consumers

26. Figure 1 below suggests that the Authority's proposal would initially increase prices for residential consumers in some regions of New Zealand and reduce prices in other regions.

27. In particular, consumers in areas benefiting greatly from recent grid upgrades, such as Auckland and Northland, would pay slightly more for transmission services each year. However, it needs to be remembered the consumers in those areas have been receiving the benefit of grid upgrades in terms of paying lower prices for energy (than what would otherwise have occurred) and avoiding costly disruptions to their electricity supply.

Figure 1: Difference between charges under the proposal and the status quo as $/year for a typical household in each distribution network



28. The following case studies illustrate key reasons for increases in charges that consumers in some areas would face:

(a) Electricity Ashburton, relative to other electricity distribution businesses (distributors), currently pay a low level of transmission charges. This is because the great majority of the peak demand periods for the upper South Island region occur in winter but demand on Electricity Ashburton's network is largely summer peaking due to irrigation load. Hence, Electricity Ashburton largely avoids the interconnection charge. In variable terms, Electricity Ashburton currently pays transmission charges of $6.10/MWh per hour.

Under the Authority's proposal, the new residual charge is based on the transmission customer's physical capacity to take electricity. Electricity Ashburton has a low average level of demand relative to its level of capacity (to accommodate the summer peak)—called a low load factor. As a result, Electricity Ashburton's transmission charges—when expressed in terms of its average demand—increase substantially, to an indicative $19.20/MWh. This rate is slightly lower than the $20.04/MWh average of all distributors.

(b) KiwiRail's current transmission charges are around $0.5m per year, and under the Authority's proposal they are estimated to increase to $2.3m per year. KiwiRail has a low load factor (ie, low average load relative to capacity), which results in it facing a relatively high portion of the proposed residual charge. The Authority understands that KiwiRail requires a high level of capacity because of its traction motors which are used to propel electric trains. Traction load is highly intermittent and currently accounts for around 60% of KiwiRail's total load.

(c) The Authority's indicative modelling indicates Vector, Northpower and Top Energy are 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 are proposed to be recovered through the area-of-benefit 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.

(d) OtagoNet has comparably lower modelled charges than other distributors because it does not benefit substantially from assets included in the area-of-benefit charge and it has a load factor that is high relative to other distributors. Distributors with high load factors typically face more stable demand and therefore do not need a lot of extra capacity to accommodate peaks in electricity demand. Therefore, OtagoNet's residual charge, which is based on capacity, is less than many other distributors.

(e) Westpower's transmission charges are currently amongst the lowest of all distributors on a variable and absolute basis, as it is well served by distributed generation within its network which enables it to avoid the current peak based interconnection charge. However, the proposed capacity based approach for the residual charge means that Westpower will not be able to avoid the transmission charge through distributed generation to the extent that it could previously. Under the proposal, the costs of the West Coast upgrade transmission project, which was provided to service the Pike River coal mine and the anticipated growth in dairy, would be recovered through the residual charge on all load, not through the area-of-benefit charge. This means the cost of the West Coast upgrade is borne by all New Zealand consumers.

29. To put these initial price effects into perspective, on average, residential consumers can immediately save more than $150 by switching from their current electricity retailer to the cheapest retailer on their network.

30. As it would take several years to implement the proposals, if the Authority proceeds with them, the price changes in the above chart are not likely to occur until 1 April 2019.

What is the current TPM?

31. The current TPM comprises three charges—a connection charge, an 'HVDC' charge and an interconnection charge:

(a) The *connection charge* recovers the costs of assets connecting transmission customers to the transmission grid. Connection charges are paid by customers who use those assets, and were approximately $128 million for the 2015/16 year.

(b) The *HVDC charge* recovers the costs of the high voltage direct current (HVDC) link between the North Island and the South Island. HVDC charges are paid by South Island generators and were about $150 million for the 2015/16 year. Currently, South Island generators pay the HVDC charge on the basis of their share of historical anytime maximum injections (HAMI) in the South Island. This is being replaced over a four-year transition period to a charge based on South Island generators' mean injections (SIMI) averaged over a five-year period.

(c) The *interconnection charge* recovers the remainder of Transpower's revenue relating to the regulated parts of the grid. This charge is paid by distributors and direct consumers. The interconnection charge is a "postage stamp" charge based on a customer's contribution to demand at peak times. Interconnection charges were about $639 million for the 2015/16 year.[4]

32. The current TPM also includes a prudent discount policy (PDP). The purpose of the PDP is to ensure that the TPM does not provide incentives for the uneconomic bypass of existing grid assets. The PDP does this by discounting the charges for a customer who would otherwise not connect to the transmission grid or would disconnect from the grid.[5] The costs of agreed prudent discounts

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4 Revenue figures from Transpower, *op. cit.*

5 To be eligible for a PDP, a party must demonstrate it has the ability to undertake a project that would allow it to bypass the grid. The discounted charges are based on the cost of the alternative project.

are recovered from customers that pay the interconnection charge. Only three prudent discount agreements have been made since the current TPM was implemented in 2008. Prior to 2008, a number of notional embedding contracts, the precursor to the prudent discount agreements, were signed, and several of these are still operative.

The material change in circumstances threshold is met

33. Clause 12.86 of the Code enables the Authority to review an approved TPM if it considers there has been a “material change in circumstances”. The Authority considers that this criterion has been met for three reasons:

    (a) Over $2 billion worth of major transmission investment has been approved since the TPM came into force, and the current TPM was not designed to adapt to changes in the level of, and need for, investment in the transmission network.

    (b) The regulatory framework has changed significantly since the current TPM was introduced. The Electricity Commission was replaced by the Authority on 1 November 2010, the function of approving grid investments was transferred to the Commerce Commission, and a new statutory objective was specified in the Act for the Authority.

    (c) Advances in technology, and the reducing costs of computational power, mean more sophisticated TPM options are now available.

34. These three reasons, considered separately or together, constitute a material change in circumstances.

Decision-making and economic framework for the TPM

35. The Authority finalised in May 2012 a decision-making and economic framework (DME framework) for the TPM review.

36. The Authority has used the DME framework to guide its consideration of the problem definition for the TPM review and to identify options to address those problems. As set out in the DME framework, the Authority has interpreted its statutory objective in the context of transmission pricing to mean that the TPM should promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers.

37. The DME framework sets out a hierarchy of charging approaches that the Authority will use to identify and assess options for the TPM. The hierarchy gives priority to market-based charges where possible because workably competitive markets tend to produce more efficient outcomes than the other approaches. If market-based charges are not practicable, the framework gives priority to exacerbators pay, beneficiaries pay and alternative charging options (in that order).

38. After considering submissions on the TPM options working paper the Authority has taken the opportunity to elaborate further on the DME framework to clarify and explain the identified problems with the current TPM. This elaboration demonstrates that the key principles underpinning the efficient recovery of the costs of transmission services are that:

(a) transmission prices should, as far as practicable, be service-based and cost-reflective

(b) the pricing methodology should be practicable and involve reasonable transaction costs.

39. The Authority has also elaborated on the relationship between the price signals provided by the TPM and the Commerce Commission's investment approval regime. In particular, the Authority's view is that inefficient price signals will lead to inefficient use of the grid. This will lead the Commerce Commission to approve transmission investment proposals that are efficient given the use of the grid, but are inefficient overall because grid use is inefficient.

Service-based and cost-reflective pricing

40. *Service-based pricing* occurs when the cost of a transmission service is charged only to those customers receiving the benefits of the service. This means the cost of the service is not charged to other transmission customers receiving other transmission services. It also means transmission customers pay higher prices for higher service levels and lower prices for lower service levels.

41. *Cost-reflective pricing* occurs when the price level for a transmission service reflects the cost of delivering the service.

42. In principle, to maximise economic efficiency, it is essential that parties receiving service improvements from upgrades to particular grid circuits face the full costs of those service improvements. This is because transmission customers make consumption, production, and investment decisions based on the relative private benefits and costs of the choices available to them. If the full cost of service improvements is reflected correctly in transmission charges then grid users face the correct incentives to take into account the costs of their activity for consumers.

43. However, a second principle applies when the services are shared with other parties. In that case, the best approach is to charge all parties at least the *incremental cost* of the service delivered to them and no more than the *standalone cost.*[6]

44. The above principles are just as relevant for grid upgrades as they are for the existing grid.

45. Another aspect of the service-based principle occurs when there are parties whose actions or inactions add to (or exacerbate) transmission costs. In this case it is best to charge the additional costs to those parties (called 'exacerbators') so that they take into account that their behaviour affects transmission costs for everyone else, and modify their behaviour if it is efficient for them to do so.

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6 Incremental costs (IC) are the additional costs of providing transmission services to one more transmission customer or subset of customers, or providing existing customers with additional services. Standalone costs (SAC) are the costs of providing transmission services or equivalent alternative services to a single customer or subset of customers. These costs are usually estimated by considering the costs of a purpose-built transmission facility (or alternative facility) to suit the needs of the customer(s). In summary, the pricing rule is: IC < price < SAC.

Practicality and transaction costs

46. The above pricing principles are relatively straightforward to apply for connection services provided to a single connection customer. However, many parties share the national grid, and so it is not clear from casual observation who uses and obtains benefits from which grid circuits. Determining this requires a method to assign the services of particular circuits to particular grid users.

47. Even if there is no attempt to target the costs of particular grid components to the parties receiving services from those components, a methodology is still required to allocate grid costs to transmission customers. The practicality of the various methodology options is therefore an important consideration in deciding the TPM.

48. In practice, there are significant costs involved with administering the TPM, and costs for transmission customers to verify that they are being charged in accordance with the methodology. There are also significant costs that transmission customers voluntarily incur to alter their activity to reduce TPM charges. Collectively, these costs are referred to as transaction costs.

49. If there are high transaction costs associated with having multiple components to the TPM, and complicated methodologies, then it can be more efficient to adopt a small number of components and adopt less rigorous but more cost-effective approaches that simplify the TPM.

Some key terms used in this paper

50. In many TPM documents the transmission grid—or the "national grid" as it is often called—refers to connection, interconnection and HVDC assets. In addition to those terms, the Authority uses the term "interconnected grid" to refer to interconnection and HVDC assets, as these assets are interconnected. We also often refer to grid circuits. These are just specific transmission lines and associated assets such as transformers.

51. This paper uses the term "customer" when it is referring to a party that has a commercial relationship with the supplier. The customers that Transpower invoices for transmission services under the TPM are called "designated transmission customers" in the Code. This paper calls these parties "transmission customers". Only transmission customers pay transmission charges under the TPM.

52. Transmission customers fall into two broad categories: generation customers and load customers. Generation customers inject electricity into the transmission system at grid injection points (GIPs) and load customers withdraw electricity at grid exit points (GXPs).

53. Load customers comprise distributors (who distribute electricity to end users) and direct consumers (which are large consumers of electricity connected directly to the grid). They are also sometimes referred to as transmission load customers.

54. Distributors also have their own load customers, typically comprising electricity retailers and medium-large commercial and industrial consumers. Distributors also have generators connected to their network, called distributed generation (DG) or sometimes called embedded generation. None of these parties are transmission customers—however, the paper often refers to them because transmission pricing influences their behaviours and decisions.

55. Finally, a "transmission consumer" is any party that consumes transmission services—ie, any party that derives benefit from transmission services, which includes most electricity consumers in New Zealand. A "grid user" is another expression for a transmission consumer.

The nodal spot market also provides transmission price signals

56. The interconnected grid is shared by many users. This sharing is coordinated by New Zealand's nodal-based spot electricity market, which rations use of the grid on a half-hourly basis.

57. The presence of nodal prices affects how to set efficient TPM charges for the interconnected grid. This is because the difference in nodal price at one node versus another represents an explicit "transport charge" for using the interconnected grid between the two nodes. Under certain conditions, the nodal market produces a reasonably efficient transport charge for using a grid circuit. This transport charge is typically low when there is spare capacity on the circuit, and high when the circuit's constraints bind.

58. The transport charge from the nodal spot market is represented by the loss and constraint excess (LCE), and LCE can be used to fund grid circuits for which

nodal pricing occurs. However, in practice LCE is insufficient to fully fund those circuits, typically providing no more than 20%–30% of the cost of providing the transmission system.

59. The shortfall in funding from LCE means that administered transmission charges—ie, the TPM—is required to make up the shortfall. But it is important to set TPM charges in ways that avoid counteracting the transport charge provided by nodal pricing.

Problems with the TPM

Problems with the connection charge

60. The current connection charge is a market-like charge and consequently service-based and cost-reflective. It is service-based because the costs of each connection service are charged to the party receiving the service. It is cost-reflective because the charge for providing connection services reflects the cost of providing the service.

61. Notwithstanding these features, the Authority has identified problems with the connection charge:

(a) It does not explicitly deal with the potential implications of the staged commissioning of transmission assets, as evidenced recently by the uncertainty associated with the charging status of the North Auckland and Northland investment.

(b) The current definition of connection and interconnection assets means that investments that join two connection assets in a loop result in those connection assets becoming interconnection assets. This means the costs of those connection assets become spread over all of Transpower's load customers. In effect, connection parties are subsidised when they invest in transmission assets to create a loop. An example of this is the connection of the Te Awamutu and Hangatiki substations (which are connection assets) as a result of the investment in a line between these substations by Waipa Networks.

(c) It allocates operating expenses within the connection pool using broad cost allocators rather than allocating actual cost, which is likely to be inefficient.

Problems with the interconnection and HVDC charges

62. The Authority is of the view that, in relation to the interconnection and HVDC charges, there are 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.*

The TPM is not sufficiently service-based or cost-reflective and so 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*.

The TPM is not sufficiently service-based or cost-reflective and so:

(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 are so poorly service-based and cost-reflective that they 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.

63. 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

64. In the Authority's view, nodal pricing provides reasonably 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.

65. 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.

66. 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.

67. 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.

68. 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.

69. Some direct consumers 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.

70. 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.

71. 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

72. 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).

73. 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.

74. 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.

75. 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. 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.

76. A further example arises in regard to gas transmission versus electricity transmission. Currently, generators have to pay for the pipeline that transports the gas for their generation. This means gas-fired generators face strong incentives to build their plants in Taranaki because they will pay zero charges for using interconnection assets to transport their electricity to 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.

77. 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

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

79. Transpower seeks approval for major investments based on its forecasts of actual grid use, whether the investments are proposed for economic or reliability reasons.[7] 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.

80. 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).

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[7] '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.

81. 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, which leads to inefficient grid investment decisions

82. 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).

83. 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.

84. 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.

85. The gas versus electricity transmission issue discussed on the previous page (paragraph 76) 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.

86. 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.[8] 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.

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8 Transpower submission to Petitions 2011/95 and 2011/96, 5 December 2014, page 7, para 26.

The current TPM is not durable

87. The current TPM is not durable, as evidenced by the almost constant lobbying for fundamental changes to the TPM. Poor durability exacerbates long-term uncertainties, potentially causing grid users to make inefficient location and investment decisions and poor operating decisions. It also leads to ongoing lobbying costs for changes to the TPM.

88. A view held by some parties is that New Zealand's interconnected grid was built for social and economic development reasons and that the costs of building the grid were spread across the country because the interconnectedness of the grid delivered broad social and economic benefits.

89. The Authority acknowledges those views. However, the limited computational power at the time the grid was originally built made it infeasible to target transmission costs to those receiving particular transmission services and so at that time the most efficient approach to dealing with broad social and economic benefits may have been to spread the costs across the country. The substantial advances in computational capabilities means the Authority is able to consider a TPM that targets transmission costs to those receiving particular transmission services that could better promote outcomes for consumers.

90. In the Authority's view, the poor durability with the current TPM is because the HVDC and interconnection charges are not service-based or cost-reflective, imposing unnecessary costs and stress on some transmission customers, particularly as they know that technological advances make it feasible to better target transmission costs. The Authority notes that the service-based and cost-reflective connection charge is subject to much less lobbying and is generally accepted by parties in the electricity sector.

Other problems

91. A discussion of other problems with the TPM is set out in the main paper. These include problems in relation to the prudent discount policy, loss and constraint excess, the recovery of network support assets, and dynamic reactive support.

Now is a good time to address these problems

92. As outlined in the section above, the fact that key elements of the current TPM are not service-based or cost-based incentivises inefficient grid use and inefficient investment in transmission and other electricity assets. This effect is ongoing, and is self-perpetuating. Consequently, the longer inefficient transmission prices remain in place, the worse the overall inefficiencies that result to the electricity system will become.

93. This suggests that the earlier these problems can be fixed the better. This is so despite the fact that parties who have invested on the back of inefficient price signals and parties who would face a rise in charges following a change to a more efficient TPM will likely strongly oppose such a change. The Authority recognises that changes in transmission prices will be seen by some parties as evidence of an unstable and uncertain regulatory regime.

94. The Authority believes that the Authority consistently and transparently pursuing its statutory objective is the best way for it to promote regulatory certainty and the

right climate for investment in the capital intensive electricity industry over the long-term.

95. The current low to moderate grid investment outlook is not a good reason for refraining from reforming the TPM at this time. The grid investment outlook is inherently uncertain and can change very quickly. As an example, the recent thermal closures in the vicinity of Auckland may create the need for further grid investment. Another example would be the need for grid investment if the aluminium smelter at Tiwai closed. Then it is likely there would be a need for significant grid investment to transport electricity north from the lower South Island region, and also the need for additional grid investment into Auckland if closure of the smelter led to the closure of the last two coal-fired units at Huntly. Accordingly, there is a sound basis for adopting a more efficient TPM now, as that would mean there is an efficient TPM in place to cater for the eventuality that the grid investment programme is expanded.

The proposed TPM

96. The Authority's proposed guidelines for a revised TPM are summarised in Table 1. The unshaded rows in the table show the main components that Transpower must implement following publication of the guidelines. Additional components that Transpower must implement if practicable and consistent with the Authority's statutory objectives are shaded in blue.

Table 1: Outline of the Authority's TPM proposal

Main components	Proposal
General component	Include general guidance regarding the matters that the TPM must be directed at to be consistent with the Authority's statutory objective.
Connection charge	Include a connection charge on the same basis as the current connection charge, subject to the possible inclusion of additional components (see shaded sections in table below).
Area-of-benefit charge	Include an area-of-benefit charge that would recover the costs of each asset (other than a connection asset) included in "an eligible investment". Eligible investments would be: (a) base capex and major capex commissioned after the publication of these guidelines (b) specified investments approved after May 2004 and exceeding $50m in value at the time of commissioning (c) Pole 2 of the HVDC link (d) the cost of any payment made by Transpower in respect of a non-transmission solution. Both load and generation would pay the charge.

Main components	Proposal
	The TPM would include a standard method to apply to eligible investments valued at $5 million or more ("high value investments"). The standard method would, to the extent practicable, allocate charges based on each customer's positive expected net benefit, or a measure of physical capacity or average injection, to the extent that the expected net benefit approach was not practicable. For eligible investments worth less than $5 million at the time of commissioning ("low value investments"), a simplified area-of-benefit method would apply. The simplified method would be required to be simple to apply, administer, and understand, and not all beneficiaries of an eligible investment would be required to be charged if that was not practicable. . The simplified charge would be phased in over as short a period of time as is practicable. The Authority is proposing that the area-of-benefit charge would use: (a) replacement cost (RC) for new eligible investments, but the Authority does not yet have a firm view about this (b) depreciated historical cost (DHC) for existing eligible investments.[9] Parties would be able to apply to have the value of an asset in an eligible investment optimised. In certain circumstances, under the standard method: (a) charges could be adjusted to reflect the marginal saving to Transpower from a customer's credible commitment to reduce its demand for transmission services or to reflect an increase in Transpower's costs if a customer plans to increase its demand for those services (b) charges could be revised when there is a material change in circumstances.
Residual charge	Apply the residual charge to Transpower's load customers, based on a measure of the physical capacity of the customer's connection to the grid. Physical capacity would be based on transformer capacity in the

[9] Replacement cost refers to the cost of replacing an asset. The value is updated periodically to reflect changes in cost. Historical cost (HC) refers to the original purchase cost of an asset. DHC reduces over time as an asset depreciates in value.

Main components	Proposal
	year prior to the publication of this paper, line capacity in the year prior to the publication of this paper, or gross anytime maximum demand (gross AMD) in the 5 years prior to publication of this paper.
Prudent discount policy (PDP)	Include a PDP that reflects the current PDP, but extend it so that: (a) prudent discounts would be available for the expected life of the relevant asset (b) prudent discounts would be available to a load if it is privately beneficial but inefficient and not for the long-term benefit of consumers to build and operate generation to disconnect their demand from the grid (c) prudent discounts would be available to a direct consumer in certain circumstances, if there is a material risk that the consumer's transmission charges would cause the consumer to close down its New Zealand plant (and so disconnect from the grid) (d) prudent discounts would be available to a customer that could establish that its transmission charges exceed the standalone costs for delivering electricity to it. (e) prudent discounts would also be available when the customer is a distributor with an embedded consumer in the same circumstances as in (c) or (d) above A prudent discount must not result in a customer paying less than the incremental cost of supplying transmission services. Any prudent discounts in (c) or (d) would be linked to key factors that would have a material effect on the decision to disconnect, for example, the world price of the product or service produced by the customer. The Authority is requesting submitter views on whether Transpower should approve PDP applications under (c), (d) and (e) or whether Transpower should be restricted to assessing and recommending on the applications and the Authority or some other party make the final decisions on those applications.
Additional components	
Staged commissioning	Transpower to consider proposing a clarification to the TPM that, if assets are commissioned such that they meet the definition of connection assets, they are charged for as connection assets (including if they will

Main components	Proposal
	ultimately be configured such that they will no longer meet the definition of connection assets)
Charging for assets when other grid investments join those assets in a loop	Transpower to consider proposing a method to ensure that charges that apply to assets that provide connection services are not affected by grid investments made by parties other than Transpower.
Allocation of operating and maintenance cost	Consider including a method to allocate operating and maintenance costs on an actual cost basis for assets subject to the connection and area-of-benefit charges.
LRMC charge (LRMC refers to long run marginal cost)	Transpower to consider proposing an LRMC charge that complements or augments (but does not duplicate) the price signals provided by nodal prices and other transmission charges.
Kvar charge	Transpower to consider proposing a kvar charge.

Connection charge

97. The current connection charge is contestable, service-based and broadly cost-reflective. It could, however, be made more cost-reflective by:

(a) Additional component 1: Clarifying that assets that meet the definition of connection assets should be charged as connection assets, including if they will ultimately be configured such that they would no longer meet the definition of "connection assets". The Authority considers this is a lower priority issue as there are likely to be limited circumstances where this could occur.

(b) Additional component 2: Including a method to ensure that the charges that apply to assets that provide connection services are not affected by a person other than Transpower connecting assets to assets owned by Transpower.

(c) Additional component 3: Reforming the allocation of operating and maintenance costs, which are currently based on broad allocators rather than actual cost. The Authority considers this is a lower priority issue because maintenance costs are generally a small component of the charges for an asset.

98. The proposed TPM guidelines provide for Transpower to include the above additional components in the TPM if Transpower considers that doing so would be practicable and consistent with relevant Code requirements. If those components are not included initially, it would be desirable for Transpower to keep each component under review and consider, in future, whether to propose a variation to the TPM to include the component.

An area-of-benefit charge

99. The Authority is proposing to replace the current HVDC and interconnection charges with two new charges: an area-of-benefit charge and a residual charge. The area-of-benefit charge would apply to eligible interconnected grid assets, and the residual charge would cover any residual revenue requirements after the connection and area-of-benefit charges have been set.

100. The Authority is proposing that the area-of-benefit charge recover the cost of non-connection assets in:
    (a) each project or programme of capital expenditure commissioned after the date of the guidelines
    (b) assets included in specified investments approved after May 2004 and exceeding $50m in value at the time of commissioning
    (c) Pole 2 of the HVDC link
    (d) the cost of any payments made by Transpower in respect of a non-transmission solution.

101. The proposed guidelines would require that the TPM include a method and process to determine the extent to which areas benefit from each eligible investment, as follows:
    (a) a simplified method to apply to each eligible investment valued at less than $5 million at the time it is commissioned (“low value investments”)
    (b) a standard method to apply to all other eligible investments (“high value investments”).

102. The key features of the proposed area-of-benefit charge are:
    (a) Under the standard and simplified approaches, both load and generation would pay the charge.
    (b) Under the standard and simplified approaches, and to the extent practicable, parties would pay charges in proportion to their share of the positive net benefits expected over the life of each eligible investment. Expected benefits would be assessed as at the later of the date of commissioning and 1 April 2019, for the expected remaining life of the relevant asset. The benefits would be assessed as the expected positive net benefits (not gross benefits) that payers of the area-of-benefit charge would receive from an eligible investment.
    (c) The standard method and the simplified method would each be required to:
        (i) for each eligible investment, identify the areas-of-benefit (in the case of the standard method) or the main areas-of-benefit (in the case of the simplified method). 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
        (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.

(d) To the extent that it is not practicable to allocate charges on expected positive net benefit, then the Authority proposes that:

   (i) charges to the relevant load customers be apportioned on the same basis that the residual charge is allocated to load customers

   (ii) charges to the relevant generation customers must be allocated on the basis of each customer's average injection.

(e) The standard method would provide for:

   (i) in certain circumstances, adjusting the standard area-of-benefit charge to reflect the marginal cost of the service that a customer receives in relation to each new investment

   (ii) in regard to the standard method, Transpower to review the estimate of benefits for any eligible investment if there is a material change of circumstances.

(f) The simplified method would be required to be simple to apply, administer, and understand. Under the simplified method, not all beneficiaries of an eligible investment would be required to be charged if that was not practicable. If that was the case, the transmission customers that are expected to receive the majority of the positive net benefits would be charged.

(g) For eligible investments commissioned after the publication of the proposed guidelines, the Authority is proposing the charges would be based on replacement cost (RC). The Authority does not, however, have a firm view yet about this approach and could choose an option like this or one of the other options discussed in the main body of the paper. The charges on existing eligible investments would be based on depreciated historical cost (DHC). The same valuation methods would apply to the standard and simplified approaches to the area-of-benefit charges.

103. The Authority is proposing the standard area-of-benefit charge be implemented in ‘one go’ at the outset, as it will initially apply to around only 20 investments. There are, however, a large number of Transpower investments below $5 million in value. To provide Transpower with flexibility to manage the implementation of the area-of-benefit charge effectively, the draft guidelines require the TPM to include a plan for phasing in the simplified area-of-benefit charge. Although delaying the implementation of the simplified approach delays efficiency gains, the Authority believes it may be more effective and less risky to first implement the standard charge, address any customer and IT-related issues with it, and then phase-in the simplified charge over a few years after the standard charge has ‘bedded in’.

Valuation of assets for the area-of-benefit charge

104. The proposal to adopt RC for new assets is because the Authority considers that RC better reflects the smooth level of service provided by transmission assets—ie, it avoids the problem that applying depreciation for charging purposes suggests that service levels reduce as an asset ages (in line with depreciation). The service level of a transmission asset generally only drops right at the end of the asset’s life but is otherwise reasonably stable.

105. The Authority does, however, have some concerns about the RC approach, including regarding the practicality of the method. The Authority does not therefore have a firm view about the RC approach at this stage, and considers historical cost or indexed historical cost approaches may also have merit.

106. If the RC approach was adopted to avoid over-recovery of an asset's replacement cost, the Authority is proposing that Transpower specify the expected life of each RC-valued asset and reduce its value and associated charges to zero once the asset has reached its expected life. Force majeure aside, charges would continue until that time whether or not the asset is replaced earlier. This provision would be adopted to avoid incentives for transmission customers to request inefficiently early asset replacements if, for example, RC values decline over time.

107. If Transpower undertakes replacement, refurbishment or maintenance investment that is expected to extend the life of an asset, the Authority proposes that the replacement, refurbishment or maintenance investment would be capitalised and charged for as a new asset with a life equal to the now expected extended life of the asset.

108. The Authority proposes to use DHC for valuing existing eligible assets, rather than RC, to avoid an immediate rebalancing of the asset values for charging purposes. When assets are replaced or refurbished, the new asset created as outlined in the previous paragraph would be valued using the same method as other new assets.

Optimisation of asset values for the area-of-benefit charge

109. For high value eligible investments, the Authority is proposing that Transpower be required to optimise the investments in certain circumstances. Optimisation means that asset values are reduced (ie, optimised) when they are no longer used to the extent originally envisaged.

110. The Authority views optimisation as a service-based and market-like approach as customers in a workably competitive market would not pay higher charges simply because another user of the asset is no longer using the asset or is using the asset to a substantially lower extent.

111. If an asset is optimised, the revenue remaining to be recovered in relation to that asset would be recovered through the residual charge as that charge is not intended to be service-based and is designed to minimise distortions to grid user behaviour.

112. The Authority is proposing that the guidelines require the TPM include a method and process for optimisation of assets in high value investments. The process would allow transmission customers to apply to Transpower for an asset to be optimised. To be eligible for optimisation, the optimised value of an asset must be less than 80% of the non-optimised value of the asset. Further criteria would apply within a period of time (to be specified in the TPM) after commissioning. This kind of limitation would reduce inefficient incentives for parties to advocate for 'gold-plated' transmission investments.

113. Transpower would have the discretion to review its calculation of ORC or ODHC for an asset if demand for the asset changes by more than 20%. Transpower

would also have the discretion to remove optimisation altogether if the criteria for optimisation is no longer met.

A residual charge on load

114. The combination of loss and constrain excess (LCE)[10], the connection, area-of-benefit, and potentially the LRMC and kvar charges (see below), will not recover all of Transpower's regulated revenue requirements. Accordingly, a residual charge has been proposed to recover the balance of revenue that Transpower is entitled to recover, or any lesser amount determined by Transpower, for example, to ensure that transmission remains competitive with an alternative (eg, mass solar).

115. The residual charge has been designed to minimise the incentives on transmission customers to invest in more costly alternatives to avoid the charge. Accordingly, the proposed residual charge has the following key features:

(a) it would be levied on all transmission load customers

(b) it would be levied on an historical measure of the physical capacity of each load customer's connection to the grid.

116. The Authority is not proposing to apply the residual charge to generators, for two reasons. The first is that, in general, generators are more sensitive to transmission charges than load, and so a residual charge applied to generation is likely to result in costly distortions to generator investment and operation decisions. . The second reason is that a very high proportion of a flat-rate residual charge on all generators, such as a MWh charge, is likely to be passed onto consumers in the form of higher wholesale electricity prices, which means load customers will end up effectively paying the charge anyway.

117. The residual charge to be allocated to load customers would be based on a measure of their physical capacity that existed prior to this issues paper. Physical capacity would be based on one of a load customer's:

(a) transformer capacity in the year prior to the publication of this paper
(b) line capacity in the year prior to the publication of this paper
(c) gross anytime maximum demand (gross AMD) in the 5 years prior to publication of this paper.

118. To the extent practicable, and to the extent that the transaction costs of doing so would not be prohibitive, gross anytime maximum demand must be anytime maximum demand, including distributed generation, demand-side management and demand response. The requirements in relation to practicability and transaction costs may mean that Transpower chooses to include a threshold for a minimum size for the calculation of the level of these activities in periods used to calculate gross AMD.

119. The time periods used to determine physical capacity would be able to be reviewed after a time period to be proposed by Transpower, in certain circumstances.

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10 LCE is a financial surplus generated by the nodal spot market for electricity. It arises from the differences in prices between different nodes in the interconnected grid.

120. If gross AMD is chosen, the Authority proposes that Transpower consider whether gross AMD should be the highest gross demand over the five-year period, the average of the highest gross demands for each of the five years, the average of the 5 highest demands during the five-year period or some other average over the five-year period. The Authority also proposes that Transpower develop methodologies for dealing with the entry of new load customers, with the aim that they face residual charges similar to comparable load customers.

121. The Authority expects the residual charge will reduce over time as old assets are replaced and refurbished, and the cost of new assets is recovered through the area-of-benefit charge.

Allocation of overhead and unallocated operating costs

122. Under the current TPM, Transpower's overhead and unallocated operating costs ('overheads') are allocated to Transpower's generation customers through their connection charge and to Transpower's load customers through the interconnection charge. The Authority's current preference is to retain the current approach for generation (ie, through the connection charge) and allocate overheads to load customers through the residual charge. However, the Authority is also considering whether Transpower's overheads should be recovered from transmission customers in proportion to each transmission customer's combined connection, area-of-benefit and residual charges. This approach would be implemented through a surcharge on each charge.

Other charges

123. The Authority is proposing that Transpower consider the following other charges as additional components:

(a) a long-run marginal cost (LRMC) charge

(b) a kvar charge.

124. The LRMC charge is a market-like charge that would restrict use of the interconnected grid when that is efficient. In particular, the Authority considers that an LRMC charge could provide an efficient price signal in advance of a major new grid investment programme. Whether such a charge would be beneficial depends, in part, on whether nodal spot prices provide an efficient signal in regard to the timing of future transmission investment.

125. Hence, in proposing an LRMC charge to supplement nodal prices, Transpower would have to demonstrate to the Authority that a price signal over and above the price signal provided by nodal pricing and other transmission charges is necessary to promote efficient investment in, and use of, the interconnected grid.

126. A kvar charge would recover the cost of static reactive investments. It is an 'exacerbator-pays' charge because those parties that exacerbate the need for static reactive investments through their actions or inactions would face the charge.

127. As with the additional components relating to the connection charge, the draft guidelines require that the TPM include the above additional components if practicable and consistent with relevant Code requirements. If the additional components are not included initially, it would be desirable for Transpower to

keep each component under review and consider, in future, whether to propose a variation to the TPM to include the component.

Prudent discount policy

128. The current TPM includes a prudent discount policy (PDP). The economic rationale for granting prudent discounts is that the discounts avoid large inefficiencies in situations that can be characterised as 'win-win'—ie, granting the discount reduces transmission charges on the applicant, avoids economic inefficiency arising from the poor alignment to costs of some transmission charges (such as the current interconnection charge or the proposed residual charge) and it avoids other transmission customers paying higher transmission charges.

129. Prudent discounts are market-like because they allow Transpower to reduce its charges to customers when that is considered to be necessary to meet the market costs of an alternative to transmission assets.

130. The Authority is of the view that the approach in the existing prudent discount policy should be extended to provide for all situations where a customer may inefficiently avoid using the grid. Specifically, subject to certain criteria, the Authority is proposing that the TPM include a prudent discount policy that is available to a load customer in any of the following circumstances:

    (a) it is beneficial privately (but not efficient or for the benefit of consumers) for the load customer to build and operate generation to disconnect its demand from the grid

    (b) subject to certain conditions, if transmission charges are a material portion of the customer's input costs, and the customer is materially at risk of closing down its New Zealand plant (and so disconnecting from the grid), having taken reasonable steps to remain viable as a going concern

    (c) the load customer can establish that its transmission charges exceed the standalone costs of delivering electricity to the customer.

131. A prudent discount would also be available when the customer is a distributor with an embedded consumer in a similar circumstance as in paragraph 130(b) or (c).

132. The Authority also considers that the current maximum 15-year term for prudent discounts is arbitrary. The Authority proposes that prudent discounts would apply for the expected life of the asset to which it applies unless Transpower and the party receiving the discount agree on a shorter time period. This will provide more certainty.

133. If a prudent discount is granted, the revenue lost would be recovered through the residual charge, which is levied on load customers only.

134. The Authority is proposing that the value of any prudent discount described in paragraph 130(b) would be linked to key factors that would have a material effect on the decision to disconnect, for example, the world price of the product or service produced by the customer. The applicant's transmission charges could be restored when its circumstances improve materially to the point that the risk of disconnection is low.

135. The Authority is aware that the proposed extensions to the prudent discount policy add to the administrative burden of the TPM. However, in the Authority's view the additional burden would not be substantial as only a few load customers could mount a compelling case that transmission charges are creating a material risk that they will have to close down their New Zealand plant and disconnect from the transmission or distribution system—it would be necessary for applicants to reveal that their transmission charges are a material portion of their input costs, and that they have already undertaken significant steps to remain viable as a going concern.

136. The Authority recognises that these extensions to the PDP would broaden Transpower's role and responsibilities with respect to the PDP. Accordingly, submitter feedback is specifically requested on whether Transpower should evaluate and make decisions about these prudent discount applications, or whether the Authority or some other party would be the more logical and appropriate party to make the decisions based on Transpower's independent analysis and assessment.

Code changes outside the TPM guidelines

137. The Authority's TPM proposal requires changes to the Code that cannot be implemented through the TPM guidelines. The Code would need to be amended to ensure that any loss and constraint excess (LCE) attributable to specific assets is to be allocated to customers that pay charges in relation to those specific assets in proportion to each customer's charges, and any remaining LCE to be allocated to customers that pay the residual charge, in proportion to each customer's charges. This is considered to be the most efficient treatment of LCE.

138. In the Connection Code, the power factor would be relaxed to 0.95 in all regions. This would provide clarity to transmission customers about the level of power factor that is acceptable, reducing uncertainty. Currently, the minimum power factor is 1.0 for some regions.

CBA of the preferred proposal

139. Economic consultants Oakley Greenwood (OGW) undertook a quantitative cost-benefit analysis (CBA) of the proposal against:

(a) the status quo, incorporating the recent changes to the TPM that arose from Transpower's operational review

(b) a deeper connection-based option, which was the same as the Authority's proposal except that it incorporated a deeper connection-based charge in place of the area-of-benefit charge. The deeper connection charge allocates transmission charges to assets which have a small number of users, determined on the basis of the Herfindahl-Hirschman index of the shares of power flows to transmission customers.

The table below gives the results of the Oakley Greenwood cost-benefit analysis of the Authority's proposal.

Table 2: Net benefits of the Authority's proposal compared to the status quo

Scenario	Net Benefit
Base case: 8% discount rate, 20-year analysis	$213 million
Scenario	**Net Benefit**
1. 6% discount rate, 20-year analysis	$242 million
2. 10% discount rate, 20-year analysis	$191 million
3. 50% reduction in the price of capital	$302 million
4. Scenario: 50% increase in diesel generation offset, 8% rate, 20 years	$217 million
5. Scenario: 50% reduction in diesel generation offset, 8% rate, 20 years	$210 million
6. 8% discount rate, 10-year analysis	$172 million
7. 8% discount rate, 30-year analysis	$258 million
8. Increased scrutiny	$233 million to $280 million[11]
9. 100% increase in implementation costs	$210 million

140. OGW also concluded that giving Transpower the option of implementing each of the additional components is likely to yield positive net benefits. It also concludes that implementing each of the LCE- and power factor-related Code changes is likely to yield net benefits.

141. The Authority is of the view that the OGW CBA provides a reasonable assessment of net benefits arising from the benefits and costs it has quantified. The Authority also accepts the conclusions of the OGW CBA that giving Transpower the option to implement the additional components is likely to yield positive net benefits.

142. In addition to the benefits OGW quantified, the Authority is of the view there are a number of large unquantified benefits that would increase the overall benefits substantially.

143. For example, there has recently been advocacy promoting undergrounding of transmission lines around Auckland. The Authority's TPM proposal would have the effect of allocating the cost to the Auckland region, which means that Auckland consumers would ultimately bear the charge. The Authority notes that undergrounding projects may not meet the requirements under the Commerce Commission's Capital Expenditure Input Methodology (Capex IM) for Transpower. However, if a separate regime was created for undergrounding investments, it is likely there would be strong pressure for beneficiaries to pay for those investments if investments under the Capex

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11 The CBA gives an incremental net benefit of $19 million to $66 million. In this table, this is added to the base case benefit of $213 million to make the figure comparable to the other figures in the table.

IM were subject to beneficiaries-pay, as would be the case under the Authority's TPM proposal. The Authority considers that making undergrounding subject to beneficiaries-pay is likely to make such investment much less likely to proceed. At a capital cost of 8%, the Authority calculates the cost savings from not proceeding with the project have a present value of $1.7 billion over 20 years. This is about $3,400 per Auckland household.[12]As a result, the Authority's proposal creates strong incentives for Auckland consumers to oppose undergrounding.[13] Even if the Authority's proposal reduced the chance of the undergrounding proceeding by 1%, that alone would save an expected $17 million—more than the cost of implementing the Authority's proposal, and so justify its introduction. Similarly, if implementation of the Authority's proposal stopped even a small percentage of this undergrounding from proceeding, that alone is expected to save more than the cost of implementing the Authority's proposal, and so justify its introduction.

144. Likewise, substantial savings would occur if implementation of the area-of-benefit proposal deferred a major investment proposal for a number of years until it was efficient to build it. For example, deferring for five years a transmission project with a capital cost of $400 million and operating costs of $20 million per year would save the economy $40 million in net present value terms.

145. These rough estimates reveal the potential for very large economic benefits to arise from the Authority's proposal to introduce area-of-benefit charges.

146. In summary, the Authority's view is that the net benefit from implementing the Authority's proposal is likely to be considerably larger than the $213 million estimated by OGW.

147. In addition, a number of other alternatives were considered on a qualitative basis for addressing the problems the Authority has identified in relation to the TPM. These were:

    (a) alternatives that could be implemented under the existing TPM guidelines, if Transpower undertook one or more further reviews

    (b) a tilted postage stamp charge

    (c) an SPD-based charge

    (d) a broad-based, low rate charge for each island or for Transpower's four transmission pricing regions, combined with an HVDC charge levied more broadly than the status quo.

148. The Authority has not proposed these alternatives because, in the Authority's assessment, they either would not address all of the problems identified by the Authority and/or would be less effective at promoting the Authority's objective.

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[12] Of course the charge would flow through to businesses as well as households, if businesses were assessed to benefit from undergrounding.

[13] This assumes that the present value of benefits is substantially less than $1.7 billion, which seems likely.

Potential impact of the proposal on transmission and electricity charges

149. The Authority has undertaken indicative modelling of the impact of the proposal on the charges to Transpower's customers and some key transmission consumers connected to distributors. The modelled charges are only indicative and are intended to be a guide for interested parties, not an accurate representation of the actual charges that will result.

150. The modelled charges will vary from the actual charges because the modelling is based on assumptions that could change, and some key parameters that will determine actual charges will be developed later by Transpower.

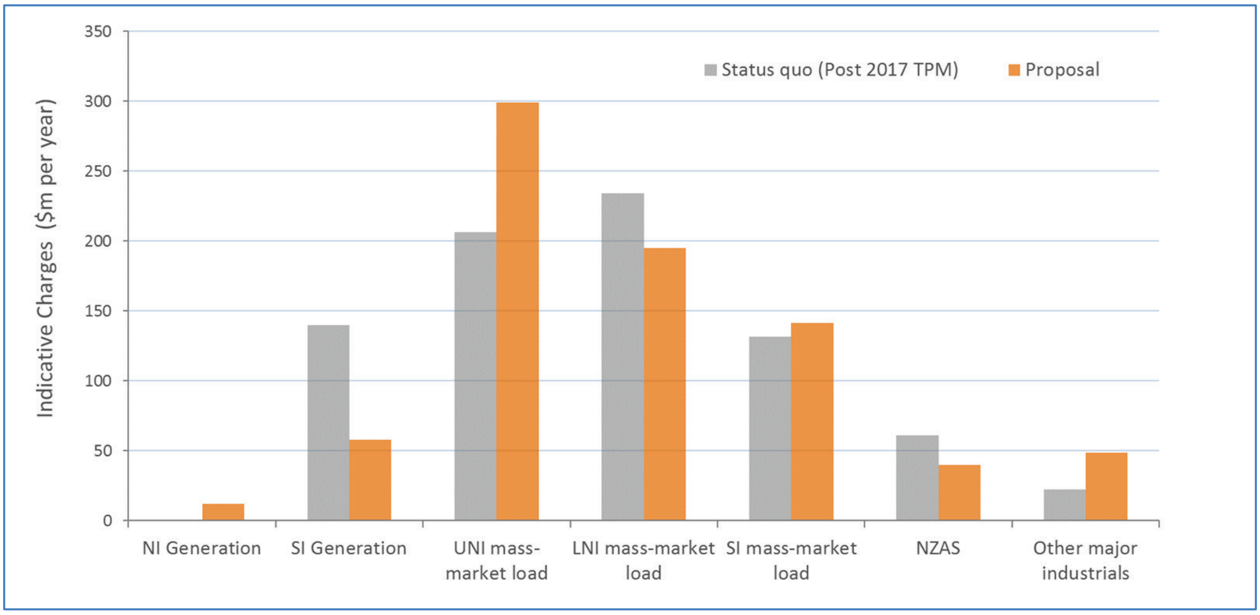
151. For example:

(a) Transpower has several high-level options for developing the standard and simplified methodologies to estimate the expected net benefits from grid investments, and many details to consider with their preferred approaches. These choices could result in the allocation of the area-of-benefit charge deviating materially from the numerical results presented in this paper.

(b) The method for allocating the residual charge among load customers is another key item for development by Transpower. As the residual charge is expected to collect around $500 million per year initially, the choice between various physical capacity measures (including gross AMD), is likely to materially alter the allocation of this charge.

152. Figures 2-6 show the indicative modelled results across customers and regions. Note the results in these charts are based on the assumptions that (1) generators do not pass through transmission charges and (2) 'avoided cost of transmission' (ACOT) payments continue to be paid as occurs under the current TPM.

Figure 2: Indicative charges by customer group ($m per year)[14]



[14] The reference in Figure 2 and subsequent figures to "Status quo (Post 2017 TPM)" is the TPM that will be in place from 1 April 2017 that incorporates the changes resulting from Transpower's 2014/15 TPM operational review.

Figure 3: Indicative charges in fully variabilised terms ($/MWh) by customer group

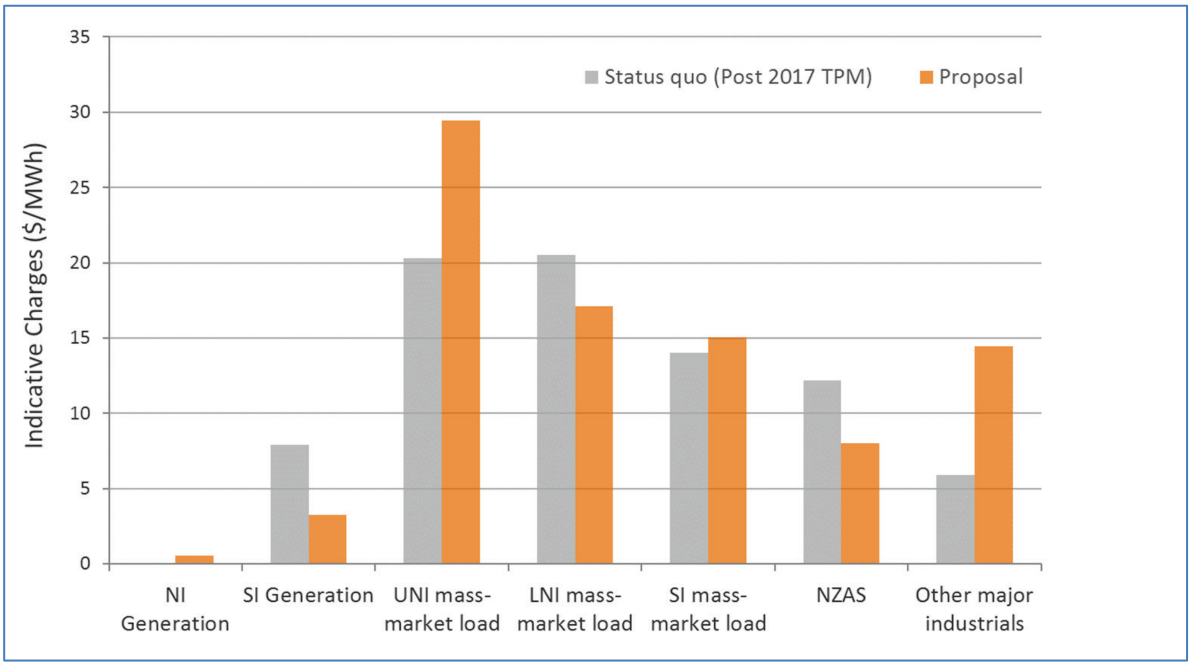


Figure 4: Heatmaps showing indicative charges for distributors under status quo (left) and proposal (right) in fully variabilised terms ($/MWh)

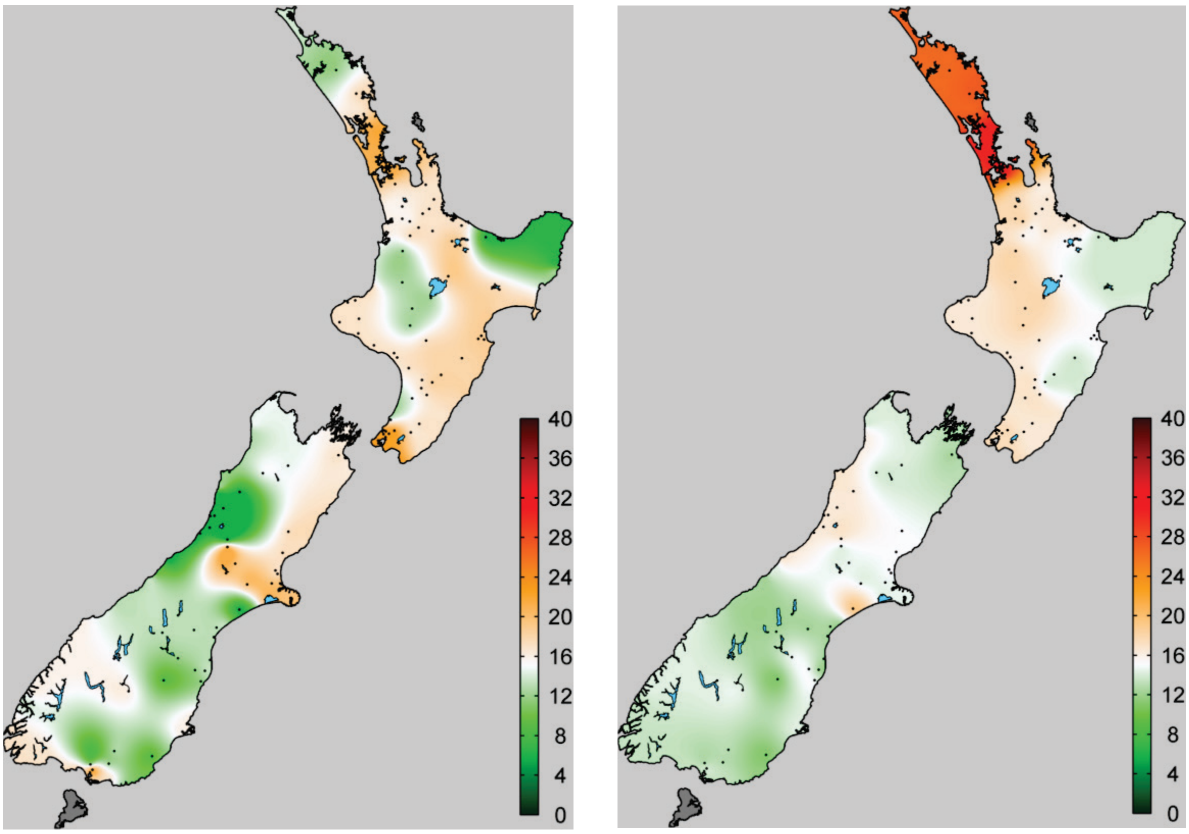


Figure 5: Indicative charges by customer in $m per year under status quo and proposal

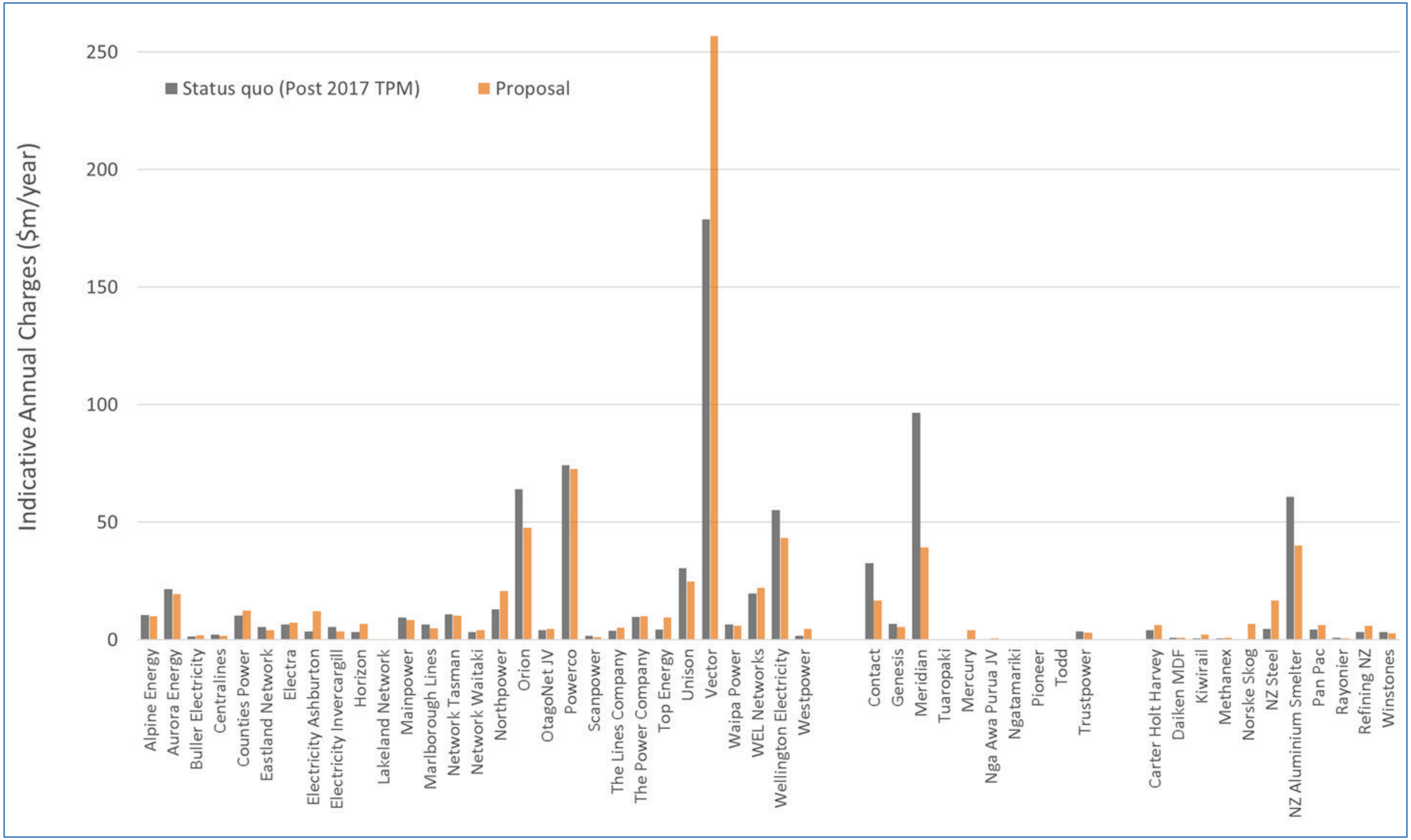
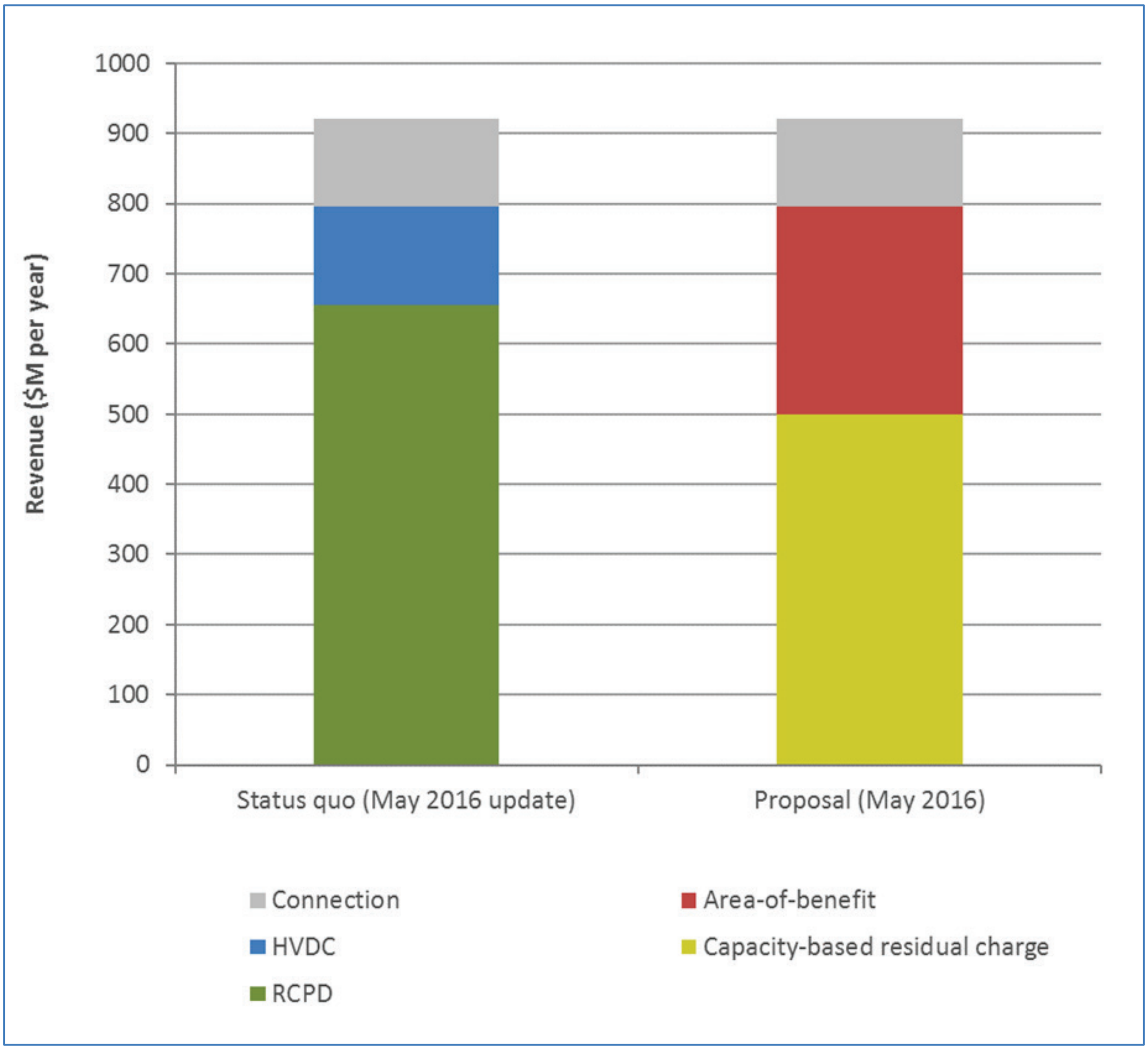


Figure 6: Recovery of Transpower's regulated revenue by charge under status quo and Authority proposal ($m per year)



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1. Introduction

About this paper

1.1 The Electricity Authority (Authority) is reviewing the guidelines that Transpower New Zealand Limited (Transpower) and the Authority must follow in setting the transmission pricing methodology (TPM). The TPM sets out how the revenue that Transpower is entitled to recover in respect of the regulated components of the grid is allocated between designated transmission customers (the parties liable to pay the charges calculated under the TPM).

1.2 The current TPM guidelines are available on the Authority's website[15] and the current TPM is set out in Schedule 12.4 of the Electricity Industry Participation Code 2010 (Code).[16] The Code is administered by the Authority.

1.3 The Authority considers that the TPM can be improved so as to better meet the Authority's statutory objective set out in section 15 of the Electricity Industry Act 2010 (Act), which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

1.4 This paper is an issues paper prepared under clause 12.81 of the Code. Accordingly, this paper sets out a proposed process for the development and approval of a new TPM, and proposed guidelines to be followed by Transpower in preparing a new TPM.

1.5 The Authority is publishing and consulting on the paper in accordance with clause 12.82 of the Code. The Authority invites submissions on this paper, in particular on the draft process and guidelines.

1.6 This paper also discusses potential amendments to the Code.[17] The amendments to the Code are matters that are related to, or consequential on, changes to the TPM under the proposed guidelines.

Submissions

1.7 The Authority prefers to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to send submissions electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with 'Second

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[15] The current guidelines are available at http://www.ea.govt.nz/development/work-programme/transmission-distribution/tpm/development/development-of-the-transmission-pricing-guidelines/

[16] The TPM has evolved through several iterations since Transpower's revenues were unbundled from the former Electricity Corporation's electricity bulk supply revenues in 1992. The evolution of the TPM has been driven by factors such as changes to the electricity industry structure, development of electricity markets and technology advances. An overview of the evolution of the TPM since 1988 is set out in Appendix B of the paper entitled 'Transmission Pricing Methodology: issues and proposal' (October 2012 issues paper). This paper is available at: https://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/.

[17] Including a potential amendment to the Connection Code, which is a document incorporated by reference into the Code. Amendments to the Connection Code must be carried out in accordance with clause 12.26 of the Code.

Issues Paper—Transmission Pricing Methodology: issues and proposal' in the subject line.

1.8 While the Authority has included a few specific questions for submitters, the Authority also seeks feedback on all aspects of this paper.

1.9 If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below:

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

1.10 Submissions should be received by 5pm on Tuesday, 26 July 2016. Late submissions are unlikely to be considered.

1.11 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

1.12 Your submission will be made publically available on the Authority's website. Submitters should indicate any documents attached, in support of their submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

Next steps

1.13 Chapter 4 explains in full the decision-making process for the TPM review. The immediate next steps, after submissions are received on this paper, are:

(a) The Authority will publish submissions.

(b) The Authority will consider the submissions and, if the Authority remains of the view that the arrangements for transmission pricing can be improved, the Authority will finalise and publish guidelines for Transpower to follow in developing a new TPM, and will also finalise and publish a process for the development of the TPM.

1.14 The Authority's indicative timing to complete these steps is late 2016.

2 Background

Introduction

2.1 This chapter:

(a) describes the costs that the TPM allocates, and how those costs are determined

(b) explains how the TPM allocates those costs to transmission customers

(c) sets out other matters that are relevant to the TPM

(d) summarises the Authority's review of the TPM so far, and the review of the TPM by Transpower.

Costs that the TPM allocates

Introduction

2.2 This section describes the costs that the TPM allocates, and how those costs are determined.

2.3 The purpose of the TPM, as set out in clause 12.78 of the Code, is to ensure that, subject to Part 4 of the Commerce Act 1986, the "full economic costs" of Transpower's transmission services are allocated in accordance with the Authority's objective.

2.4 The transmission services provided by Transpower are regulated by the Commerce Commission in accordance with the price-quality regulation in Part 4 of the Commerce Act 1986.[18] Under the price-quality regulation that applies to Transpower, the Commerce Commission determines the maximum allowable revenue (MAR) that Transpower may recover for each pricing year (1 April to 31 March).[19] In addition to the MAR, Transpower may also recover certain pass-through costs and specified recoverable costs. The MAR, the pass-through costs, and the recoverable costs together comprise the costs that are allocated under the TPM, and are collectively referred in this paper to as "Transpower's revenue".

Costs of approved investments

2.5 Transpower's full economic costs include the costs of "approved investments".[20]

2.6 Under clause 1.1 of the Code, an approved investment is:[21]

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[18] Transpower is the only provider of transmission services in New Zealand—transmission grids are typically a natural monopoly because high fixed costs and low marginal costs make it uneconomic to develop a second and competing grid in a particular market or location.

[19] The price-quality regulation also sets out minimum quality standards. More information about the role of the Commerce Commission and individual price-quality regulation for Transpower is available at: http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/.

[20] Under clause 12.77 of the Code, the costs in relation to approved investments are recoverable by Transpower under the TPM.

[21] This section of the paper does not discuss (a) or (b) in detail.

(a) an investment approved under section III of part F of the former Electricity Governance Rules 2003. These are investments that were approved by the Electricity Commission before the Code came into force

(b) an investment approved by the Commerce Commission under section 54R of the Commerce Act 1986. These are investments that were approved by the Commerce Commission under transitional provisions, before the input methodologies in (c) were completed

(c) an investment that is permitted under an input methodology determined by the Commerce Commission under section 54S of the Commerce Act 1986.

2.7 In relation to paragraph (c) above, the input methodology that applies to Transpower's capital expenditure for regulated transmission services is the Transpower Capital Expenditure Input Methodology (Capex IM).[22]

2.8 The Capex IM sets out the processes for submitting, assessing and approving Transpower's capital expenditure proposals. If capital expenditure is approved, the value of the asset at commissioning is added to Transpower's regulated asset base. The regulated asset base is used to calculate the MAR, and so affects the amount that Transpower can recover under the TPM.[23]

2.9 The Capex IM divides capital expenditure into base capex and major capex, as follows:

(a) base capex is capital expenditure on certain types of asset replacement, asset refurbishment, business support, and information systems and technology assets, along with other expenditure that does not exceed the base capex threshold of $20 million

(b) major capex is capital expenditure incurred to ensure the grid meets the Grid Reliability Standards (GRS), or where there is a net electricity market benefit (for example, to reduce energy losses or dispatch constraints).[24] Major capex may include expenditure on transmission or non-transmission solutions.

2.10 The Capex IM sets out different processes for the approval of base capex and major capex:

(a) For base capex, Transpower is periodically required to submit a base capex proposal for the upcoming 5 years. After assessing the proposal, the Commerce Commission sets a base capex allowance. Once the allowance is set, it is up to Transpower to decide how much investment it actually undertakes. Over or under-expenditure of the allowance is dealt with via a mechanism in the Capex IM that provides incentives for Transpower to achieve cost efficiency gains and to deliver the agreed outputs.

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22 A consolidated version of the Transpower Capital Expenditure Input Methodology Determination, incorporating changes to the Capex IM since it was made in January 2012, as at 5 February 2015, is available at: http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/transpower-input-methodologies/.

23 Regulated asset values form part of the building block calculation of Transpower's maximum allowable revenues by the Commerce Commission.

24 See the Capex IM, Schedule D1 Division 1.

(b) For major capex, Transpower may submit a major capex proposal to the Commerce Commission at any time. The Commerce Commission must assess major capex proposals against an "investment test". The investment test will be satisfied if an investment has a positive expected net electricity market benefit (unless the investment is necessary to meet the deterministic limb of the GRS)[25] and the expected net electricity market benefit is the highest compared with other investment options.[26] The Commerce Commission may only decline or approve a major capex proposal—it may not amend a proposal. However, the Commerce Commission may, on application by Transpower, approve an amendment to a major capex investment after it has approved the investment.

2.11 Interested parties have the opportunity to participate during the process for the approval of base capex and major capex.[27] However, submissions by interested parties do not determine whether the investment will proceed, or when, or according to what design.

Costs of other investments allocated under the TPM

2.12 Clause 1 of the TPM clarifies that the "full economic costs" of Transpower's services include costs relating to investments which are not subject to approval by the Commerce Commission under section 54R of the Commerce Act 1986, or to which the input methodology under section 54S of the Commerce Act applies.

2.13 That provision reflects the fact that not all investments that have been added to Transpower's regulated asset base were subject to approval by the Commerce Commission or, prior to 1 November 2010, the Electricity Commission.

Some of Transpower's costs are not allocated under the TPM

2.14 Some of Transpower's costs are not allocated under the TPM because they are already recovered in another way.

2.15 The TPM does not recover the costs associated with:

(a) investment contracts between Transpower and connection parties allowed under clauses 12.70, 12.71 and 12.95 of the Code

(b) a number of specific notional embedding contracts and fixed-term input connection contracts agreed under TPMs that applied prior to 2008

(c) Transpower’s non-regulated activities (for example, costs associated with its subsidiary businesses), or

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25 The deterministic limb of the GRS (ie, the N-1 safety net) is in clause 2(b) of Schedule 12.2 of the Code. Under that limb, the grid reliability standards are satisfied if, with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following a single credible contingency event in the core grid. In other words, the deterministic limb of the GRS relates to investments directed at ensuring that the core grid meets the N-1 security standard. For those types of investment, the expected net electricity market benefit may be negative (ie, result in an expected net electricity market cost). For an investment that is required to ensure that the core grid meets the N-1 security standard, the Commerce Commission may approve the investment with the lowest expected net electricity market cost.

26 The investment must also be "sufficiently robust" under sensitivity analysis.

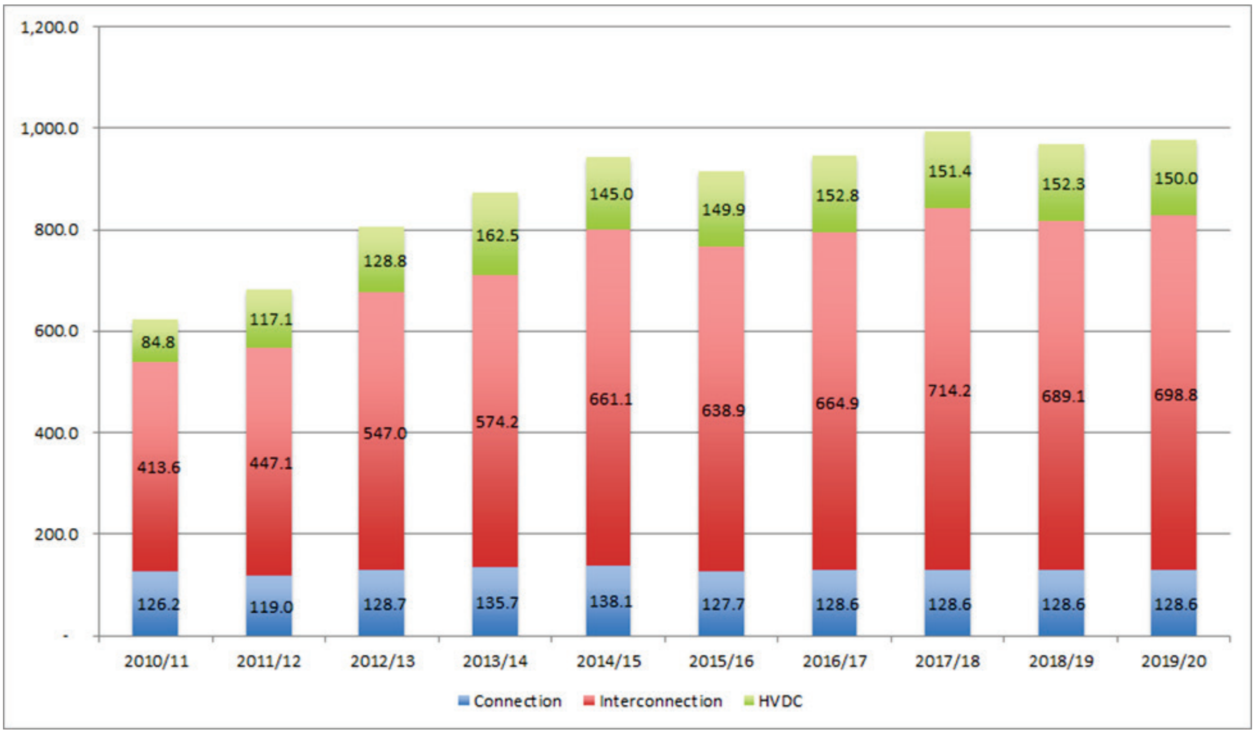
27 See clauses 3.2.1(b) and 3.3.1, and Part 8 of the Capex IM.

(d) Transpower performing roles under the Act or Code other than its role as grid owner, such as acting as the system operator or FTR manager.

Scale of the costs recovered under the TPM

2.16 Figure 7 shows a breakdown of the actual and forecast revenue for Transpower for the period from 2010/11 to 2019/20.

Figure 7: Actual and forecast revenues recovered by transmission charges 2010/11 to 2019/2020[28]



2.17 As shown in Figure 7 the revenue for the remainder of the current regulatory period is forecast to rise from $916.6 million for the 2015/16 pricing year to $977.4 million for the 2019/20 pricing year.[29]

How the TPM allocates costs

2.18 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

2.19 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.[30]

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[28] Source: Transpower.

[29] Note that forecast revenue does not perfectly align with the MAR because forecast revenue takes into account adjustments to correct under and over recovery from previous years.

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

2.20 Transmission customers are:[31]

(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.

2.21 Transpower must charge for its transmission services in accordance with the TPM. The TPM is incorporated in transmission agreements[32] between Transpower and each transmission customer, and charges payable are recoverable as a debt due to Transpower.[33]

Connection charge

2.22 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.[34] Connection charges were about $128 million for the 2015/16 pricing year.

Charge is based on deep connection approach

2.23 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.

2.24 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 maintenance component, an operating component and, for injection customers, an overhead component.[35]

Asset component

2.25 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.

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[31] See Schedule 12.1 of the Code.

[32] Clause 12.102 of the Code.

[33] Clause 12.95 of the Code.

[34] 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 (see clause 25 of the TPM).

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

2.26 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

2.27 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

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

2.29 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 (ie, the original cost of building the assets).

2.30 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.[36]

2.31 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

2.32 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 $150 million for the 2015/16 pricing year.

2.33 HVDC charges are paid by South Island generators based on their share of peak injections in the South Island (historical anytime maximum injection or HAMI).[37]

2.34 As a result of Transpower's operational review, the Authority recently approved an amendment to the TPM 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. The new approach is called the South Island Mean Injection (SIMI) charge. The HAMI-

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

[37] 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 Island generation connection location during the four immediately preceding pricing years, whichever is highest. Refer clause 3, Schedule 12.4 of the Code.

based charge will be phased out (and the SIMI-based charge phased in) over a 4-year period beginning on 1 April 2017.

Interconnection charge

2.35 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.

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

2.37 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).[38] Currently, N is 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) that will change N for all regions to 100.

Prudent discount policy

2.38 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.[39]

2.39 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'—ie, 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.

2.40 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).

2.41 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):

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[38] Refer clause 3, Schedule 12.4 of the Code.
[39] Clause 36, Schedule 12.4 of the Code.

(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.

2.42 Transpower currently has three prudent discount agreements in place.[40] 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.

Other matters relevant to the TPM

2.43 This section describes other matters that are relevant to the TPM.

Loss and constraint excess

2.44 Loss and constraint excess (LCE) payments are not regulated under the current TPM.

2.45 LCE payments do not (and cannot, under the current Code)[41] reduce the amount of transmission costs recovered under the TPM. However, LCE payments are received by customers as a credit note against transmission charges, so customers "see" LCE payments as reducing/offsetting their transmission charges.

2.46 Therefore, LCE payments affect the incentives created by the TPM. Accordingly, the Authority has included LCE payments in the TPM review.

2.47 Transpower receives LCE from the clearing manager under clause 14.16 of the Code. The LCE received by Transpower is net of any LCE used to settle FTRs under the Code.[42] It also includes residual LCE, which is the surplus revenue that the clearing manager holds after settling FTRs.[43]

2.48 The Benchmark Agreement[44] states that Transpower will calculate, in accordance with its "prevailing methodology" for distribution of LCE, the share of

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40 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.

41 Clause 12.77 of the Code requires that Transpower's costs in relation to an approved investment are recovered from designated transmission customers under the TPM, and clause 12.78 requires the TPM to allocate the full economic costs of Transpower's transmission services. In contrast, LCE is a component of the revenue recovered in the wholesale electricity market from retailers and direct consumers that purchase electricity from the clearing manager.

42 See clause 14.16(7) of the Code.

43 See clause 14.16(7) of the Code. Residual LCE may include FTR auction revenue, though this depends on the outcome of the FTR market and whether auction revenue is required to settle FTRs. In this paper, the LCE and residual LCE received by Transpower under clause 14.16 are together referred to as LCE, unless the context requires a different interpretation.

44 The Benchmark Agreement is incorporated by reference in the Code. The Benchmark Agreement applies as a default transmission agreement between Transpower and a transmission customer if the parties cannot agree

LCE (net of any GST received) to be allocated to each transmission customer.[45] In other words, the Benchmark Agreement assumes that Transpower has a methodology for allocating LCE to transmission customers, but does not specify that methodology.

2.49 Under Transpower's current "prevailing methodology",[46] Transpower first determines the proportion of LCE to be allocated to each of three asset classes—connection, interconnection and HVDC. The proportions are, broadly speaking, based on the LCE generated for each asset class.

2.50 Once the LCE is allocated to the three asset classes, Transpower allocates the LCE in each asset class to customers, as follows:

(a) **LCE for the connection asset class:** to customers that pay for connection assets, based on the customer charge allocation in the TPM/contracts

(b) **LCE for the HVDC asset class:** to customers that pay HVDC charges (ie, South Island generators) in proportion to each customer's contribution to total HAMI

(c) **LCE for the interconnection asset class:** to customers that pay interconnection charges, in proportion to each customer's contribution to the payment of interconnection charges under the TPM.

2.51 Having determined the LCE to be allocated to each customer, Transpower then issues each customer a credit note for the customer's share of LCE. The credit note is issued at the same time as the invoice for grid charges for the month following the month in which LCE payment is received.

Network reactive support

2.52 Most of the New Zealand power system is an alternating current (AC) network. Elements of AC systems generate and consume two kinds of power: real power and reactive power. Real power provides heat, light and motive power. Reactive power supports the voltage and is essential for reliably operating the system.

2.53 The transmission network requires reactive support equipment at different places in the system to compensate for reactive power generated or consumed and to carefully control voltage levels to avoid power cuts in the event of unexpected system events. Controlling reactive power flows helps to avoid voltage collapse following unexpected events, reduces losses, and, in some cases, alleviates transmission constraints.

2.54 The Code provides for two broad types of reactive support.

2.55 **Static reactive support** relates to steady state voltage management and provides support to compensate for on-going reactive power issues. For example, switching capacitor banks or dispatch of generator reactive capability to

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terms for connection/use of the grid. The Authority understands that all transmission agreements are default transmission agreements based on the Benchmark Agreement.

45 Benchmark Agreement, Clause 45.1 of Part D.

46 Refer Transpower, *Transmission rentals (Losses and constraints excess payments),* March 2008. Available at: https://www.transpower.co.nz/sites/default/files/publications/resources/transmission-rentals-2008.pdf.

maintain normal voltage levels. This type of reactive support can respond to changes in the power system, but on a daily rather than millisecond basis.

2.56 The costs of interconnection assets that provide static reactive support[47] are currently recovered in the same way as other interconnection assets.

2.57 **Dynamic reactive support** maintains voltage within acceptable limits in the milliseconds following unexpected outages and helps avoid widespread loss of supply. Examples of dynamic reactive support are fast acting generator reactive capability or static var compensators (SVCs).

2.58 Dynamic reactive support is currently procured by the system operator. The system operator voltage support procurement costs are recovered under Part 8 of the Code, from distributors and direct consumers through a peak reactive power demand charging regime, and from non-compliant generators (those that cannot meet their Asset Owner Performance Obligations (AOPOs)[48] and have entered into an equivalence arrangement with the system operator).

2.59 However, recent investment by Transpower in dynamic reactive support beyond that provided by generators, such as the SVC constructed at Marsden, has been funded through the interconnection charge.

2.60 Generally, investment in dynamic reactive support is more costly than investment in static reactive support. Both the fixed and variable costs of producing static reactive power are much lower than those of producing dynamic reactive power. However, the reactive power capability from a dynamic source can be adjusted much more quickly.

Reviews of the current TPM

2.61 This section describes how the TPM has been reviewed since the current TPM took effect (1 April 2008).

Review by the Authority

2.62 The Authority's predecessor, the Electricity Commission, initiated a review of the TPM in April 2009. The Electricity Commission established a Transmission Pricing Technical Group (TPTG) in April 2009 to provide advice and assistance on the TPM review. The New Zealand Electricity Industry Steering Group, which was established by the CEOs' Forum,[49] undertook a review of transmission pricing around the same time, and submitted a report to the Electricity Commission in December 2009.

2.63 The Electricity Commission began the TPM review for the following key reasons:

(a) the Electricity Commission had approved Transpower making transmission investments in excess of $2.6 billion

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47 These assets are most commonly switched static capacitor banks, which inject a fixed level of reactive power into the grid when switched on. They are needed in regions where relatively little generating capacity is connected. Generators normally provide the reactive power needed to maintain healthy grid voltage levels.

48 AOPOs require that generators must be capable of importing and exporting specified quantities of reactive power over specified voltage ranges.

49 The CEOs' Forum comprised the CEOs of a number of major energy companies.

(b) it was recognised that there was a potential for power flows across the grid to change as a result of investment in transmission and generation, and changes in the location of demand

(c) there was an increasing emphasis on security of electricity supply

(d) several parties had requested that the Electricity Commission review aspects of the TPM.

2.64 The Electricity Commission completed two rounds of consultation, one in 2009 and one in 2010, on options for the design of the TPM.[50]

2.65 The Authority replaced the Electricity Commission on 1 November 2010 and continued the TPM review. The Authority took into consideration the work of the Electricity Commission on the TPM review. It also took into consideration advice from the CEOs' Forum that the TPM review should be the Authority's top priority project and that a consensus amongst participants had been reached on the best solution for the TPM.

2.66 The Authority subsequently:

(a) established the Transmission Pricing Advisory Group (TPAG).[51] The TPAG comprised an independent Chair and consumer and participant representatives, and was tasked with advising the Authority on the TPM. The TPAG provided the Authority with analysis and findings on options for the TPM in August 2011, but was unable to provide unanimous recommendations on the most significant aspects of the TPM

(b) consulted in early 2012 on a decision-making and economic framework for the TPM review. The Authority published the decision-making and economic framework in May 2012[52]

(c) consulted on the paper 'Transmission Pricing Methodology: issues and proposal', which the Authority released in October 2012, to obtain feedback on a package of charging approaches (October 2012 issues paper).[53] The consultation included a TPM conference on 29–31 May 2013, which was attended by all Board members

(d) consulted on the following working papers to develop and further consider key aspects of a revised TPM proposal:[54]

(i) cost benefit analysis (CBA). This working paper outlined a revised approach to apply to the cost-benefit analysis of a revised TPM proposal (3 September 2013)

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50 The Electricity Commission's stage 1 and stage 2 documents are available at: https://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/.

51 The terms of reference of the TPAG are available at: https://www.ea.govt.nz/dmsdocument/2552.

52 The Authority's decision-making and economic framework is available at: https://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/.

53 The Authority's October issues paper is available at: https://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/.

54 The nine working papers are available at: https://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/.

(ii) sunk costs. This working paper examined the extent to which the costs involved in the provision of electricity transmission services are actually "sunk", and the implications for transmission pricing (8 October 2013)

(iii) avoided cost of transmission (ACOT) payments for distributed generation. This working paper considered the efficiency implications of changes to the TPM that may reduce the quantum of ACOT payments, assuming the current ACOT payment policies were maintained (19 November 2013)

(iv) use of loss and constraint excess (LCE) to offset transmission charges. This working paper explored submissions made on the October 2012 issues paper, and at the TPM conference, that the proposed use of LCE to offset transmission charges would distort otherwise efficient wholesale market signals (21 January 2014)

(v) beneficiaries pay options. This working paper examined options for applying a beneficiaries pay charge (21 January 2014)

(vi) connection charges. This working paper examined whether the 'pool charging approach' for connection assets is efficient, whether there is potential for connection assets to be inefficiently classified as interconnection assets, and the approach to charging for operating and maintenance costs (13 May 2014)

(vii) LRMC charges. This working paper examined whether the use of long-run marginal cost (LRMC) transmission charges to recover the costs of the High Voltage Direct Current (HVDC) link and interconnection assets would better promote the Authority's statutory objective than maintaining the status quo (29 July 2014)

(viii) problem definition relating to interconnection and HVDC assets. This working paper discussed and, to the extent practicable, quantified problems with the current TPM as they related to interconnection and HVDC charges (16 September 2014)

(ix) TPM options. This working paper assessed potential options to address the problems identified in relation to the TPM. Each option comprised a package of charges (16 June 2015)

(e) decided to develop a second issues paper.

2.67 In a number of working papers, the Authority stated that it would release a working paper on an approach to a residual charge. However, after taking into account submissions on some of the working papers listed above, the Authority incorporated its thinking on the residual charge into the TPM options working paper.

2.68 Further, the Authority is separately considering amendments to Part 6 of the Code, including in relation to avoided cost of transmission, avoided cost of distribution, and connection charges for distributed generation.

Review by Transpower (Transpower's operational review of the TPM)

2.69 In 2014/15, Transpower undertook an operational review of the TPM. The operational review was limited to determining whether opportunities existed for "fine tuning" the TPM within the constraints of the existing TPM guidelines.[55]

2.70 Transpower's operational review highlighted that the TPM has not adapted to changes in transmission investment, resulting in exaggerated pricing signals. The review also provided evidence that there are problems with the current HVDC and interconnection charges.

2.71 In February 2015, Transpower submitted a proposed variation to the TPM, comprising a number of components, and submitted additional components in March 2015.

2.72 The Authority consulted on five of the components. In July and August 2015, the Authority approved the following variations to the TPM:[56]

(a) the Upper North Island and Upper South Island regions will have interconnection charges based on N = 100 trading periods (compared with N = 12 trading periods originally)

(b) the capacity measurement period (CMP) used to determine regional peak demand periods will exclude summer trading periods for the Upper North Island, Lower North Island and Lower South Island regions

(c) a new provision will be added to address any adverse pricing effects of a grid exit point (GXP tie)

(d) South Island generators will be charged for HVDC based on their average MWh injections, averaged over 5 years (the SIMI-based charge).

2.73 These amendments will come into force on 1 April 2017, ie, for the calculation of prices for the 2017/18 pricing year and subsequent years. As the capacity measurement period for the 2017/18 pricing year began on 1 September 2015, this meant that participants will have taken into account the impact of the changes from 1 September 2015.

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55 Transpower, TPM operational review: Second consultation paper, 13 November 2014, page 8.

56 The Authority's decisions and reasons papers on this issue are available at: http://www.ea.govt.nz/dmsdocument/19648, and http://www.ea.govt.nz/dmsdocument/19845.

3 Material change in circumstances

Introduction

3.1 This chapter describes the basis on which the Authority has determined that the material change in circumstances threshold in clause 12.86 of the Code has been met. It also describes the relationship between the material change in circumstances and the options considered by the Authority.

Material change in circumstances

3.2 Clause 12.86 of the Code provides that the Authority may review an approved transmission pricing methodology if it considers that there has been a material change in circumstances.

3.3 In the October 2012 issues paper, as well as in some of the working papers,[57] the Authority set out matters that it considered constituted a material change in circumstances. In response to those papers, and at the TPM conference, a number of submitters stated that the Authority had failed to demonstrate that the "material change in circumstances" threshold had been met, and that the Authority therefore did not have the grounds to review the TPM.

3.4 The Authority has considered those submissions. However, the Authority remains of the view that there has been a material change in circumstances for the reasons set out below.

3.5 The Authority also considers that it can review the TPM in its entirety. This is consistent with ensuring that the TPM meets its purpose, as specified in clause 12.78 of the Code, and that the TPM is consistent with the Authority's objective.

3.6 Since the TPM came into force:

(a) Over $2 billion worth of transmission investment has been approved or commissioned.[58] This has included major investments such as the Otahuhu substation diversity project, HVDC pole 3, the North Auckland and Northland project, and the North Island grid upgrade.[59] Each of those investments has now been constructed and commissioned. The Authority considers that the current TPM was not designed to adapt to changes in the level of and need for investment in the transmission network.[60] Also, the

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57 See TPM options working paper, and Problem definition relating to interconnection and HVDC assets working paper, which are available at: https://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/.

58 Those investments were approved by the Electricity Commission before 2010, and, since 2010, by the Commerce Commission.

59 The former Electricity Commission made a final decision on the TPM in June 2007. The Electricity Governance Rules were amended to include the TPM in September of that year, and the TPM applied from April 2008. The first major grid investment approved by the Electricity Commission, the North Island grid upgrade, was approved in July 2007.

60 Transpower's opening Regulatory Asset Base (RAB) is expected to increase from a value of $2,606.7 million in 2011/12 to an expected value of $4,610.2 million in 2015/16, an increase of 77%. Source: Companion paper to final determination of Transpower's individual price-quality path for 2015-2020, available at http://comcom.govt.nz/regulated-industries/electricity/electricity-transmission/. The resulting increase in Transpower's MAR has affected the TPM pricing signals.

costs of those investments must be recovered under the TPM.[61] Given the large increase in TPM charges caused by recent investments being commissioned and added to the Regulatory Asset Base (RAB), the Authority considers that any existing inefficiency within the TPM will be magnified.

(b) There have been significant changes to the regulatory framework, with the Authority replacing the Electricity Commission from 1 November 2010. In particular, the Authority's statutory objective is different from the Electricity Commission's statutory objective under the Electricity Act 1992. The TPM was prepared on the basis of the current guidelines, which were prepared and approved by the Electricity Commission on the basis of the Electricity Commission's statutory objective. It is appropriate for the Authority to consider whether the guidelines and the TPM best promote the Authority's statutory objective. Also, the function of approving grid investments has been transferred from the Electricity Commission to the Commerce Commission.

(c) Advances in technology and the reducing costs of computational power mean that more sophisticated methods for measuring transmission services and identifying who is receiving those services are available.

3.7 Although the Code does not define what is meant by "material change in circumstances", the Authority is of the view that, by whatever definition, and whether regarded separately or together, the changes referred to above constitute a material change in circumstances of the type anticipated by clause 12.86 of the Code.

Relationship between material change and options considered

3.8 In respect of the October 2012 issues paper and working papers, some submitters:

(a) questioned whether a material change in circumstances in relation to one aspect of the TPM could justify a wider change to the TPM

(b) considered that the Authority can only investigate options that address the issues arising from the material change in circumstances.

3.9 The Authority has considered those submissions. However, the Authority's view is that the material change in circumstances threshold does not restrict the Authority to proposing changes that address only the issues arising from the material change in circumstances, for the reasons set out below.

3.10 The TPM is part of the Code. Under section 32(1) of the Act, the Code may only contain provisions that are consistent with the Authority's statutory objective and that are necessary or desirable to promote any or all of the matters listed in section 32(1). Those matters repeat aspects of the Authority's statutory objective. In the Code, the requirements of the Act are reflected in clause 12.89 (which requires Transpower to develop a TPM consistent with the Authority's

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61 Refer to clause 12.77 of the Code.

statutory objective) and clause 12.91 (which provides for the Authority to refer a proposed TPM back to Transpower if the TPM does not adequately conform to the requirements of clause 12.89).

3.11 Therefore, once the material change in circumstances threshold is met, the Authority is required by the Act and the Code to consider whether a problem with the TPM exists that necessitates a change to the Code in order to better promote the Authority's statutory objective. Further, in considering potential changes to the Code, the Authority must determine whether amending the Code is necessary or desirable to promote the matters specified in section 32(1). In summary, to meet the requirements of the Act (section 32(1)) and the Code (clause 12.89), the proposal for a change to the Code may include aspects addressing issues other than the issues arising from the material change in circumstances.

4 Decision-making about the TPM

Introduction

4.1 This chapter describes the Authority's process for reviewing the TPM. It also describes the Authority's decision-making and economic framework, which the Authority uses to guide its consideration of the problem definition and identification of options to address those problems.

Decision-making in the TPM review—summary of steps

4.2 So far, the Authority's TPM review has involved the Authority:

(a) publishing an issues paper in October 2012 on the proposed process and proposed guidelines for Transpower to follow in developing a new TPM

(b) considering submissions received on the October 2012 issues paper and at the TPM conference held in May 2013

(c) publishing and considering submissions on a series of working papers on key aspects of a revised TPM proposal

(d) publishing a second issues paper (ie, this paper) on the revised proposed process, and revised proposed guidelines, for Transpower to follow in developing a new TPM.

4.3 The Authority will consider submissions received on this second issues paper. If the Authority decides that a new TPM would better meet the Authority's statutory objective, the Authority intends to:

(a) publish a process for the development of the TPM and final guidelines for Transpower to follow in developing the TPM (as required by clause 12.83 of the Code)

(b) request Transpower to submit a proposed TPM. Clause 12.79 of the Code requires Transpower, in developing a TPM, to assess the TPM against the Authority's objective. Transpower must also develop the TPM consistent with the matters in clause 12.89(1) of the Code

(c) consider the proposed TPM submitted by Transpower,[62] and, as provided for in clause 12.91 of the Code, either approve the TPM for consultation, or, in certain circumstances, refer the proposed TPM back to Transpower. If Transpower subsequently re-submits a proposed TPM for consideration, the Authority will either approve the resubmitted TPM for consultation, or amend the resubmitted TPM, before the Authority publishes the resubmitted proposed TPM for consultation

(d) consult on the proposed TPM as soon as practicable, under clause 12.92 of the Code. This consultation will double as the consultation required under section 39 of the Act to amend the Code.

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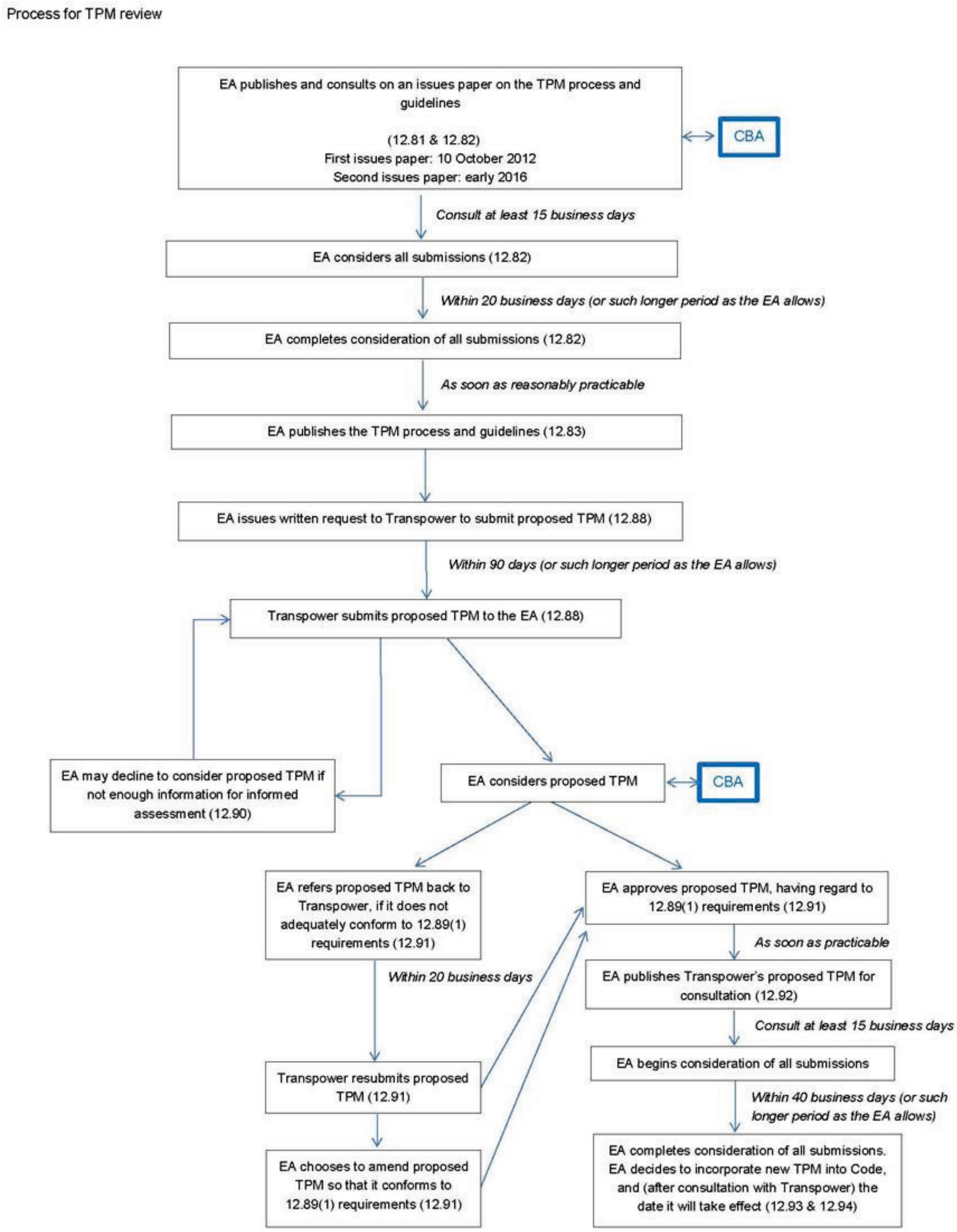
[62] The Authority may decline to consider the proposed TPM if, in the Authority's view, Transpower has not provided sufficient information for the Authority to make an informed assessment. If that happens, the Authority must advise Transpower of the extra information required, and Transpower must provide a revised TPM (clause 12.90 of the Code).

4.4 The Authority has previously stated that it would hold a conference following the publication of this second issues paper.[63] However, the Authority is now of the view that a conference is not necessary. The Authority has received useful feedback through the extensive consultation process and will receive further information from submissions on this paper. The Authority is of the view that holding a conference would not add useful information to that expressed in submissions, and would add time and cost to the process for interested parties, without additional benefits.

4.5 A flow chart of the process that the Authority proposes to follow for developing the TPM is set out in Figure 8.

[63] See TPM options working paper, page 6, which is available at: [url]

Figure 8: Process proposed for developing the TPM



4.6 In following the process described above, the Authority will comply with its obligations under the Act, the Commerce Act, and the Code. The process also reflects guidance provided by the consultation charter (including the Code amendment principles (CAPs)), and the Authority's decision-making and economic framework. The Authority elaborates on each of these aspects further below.

Obligations under the Act and the Commerce Act

4.7 Section 32(1) of the Act provides that the Code may include provisions that are consistent with the Authority's statutory objective, and that are necessary or desirable to promote competition in the electricity industry, the reliable supply of electricity to consumers, or the efficient operation of the electricity industry.

4.8 The TPM is a schedule of the Code, so any provision in, or amendment to, the TPM must be consistent with the Authority's statutory objective, and be necessary or desirable to promote the factors outlined above.

4.9 In order to ensure that any new TPM is consistent with the Authority's statutory objective, the Authority will assess options against each limb of its statutory objective to ensure that the Authority's statutory objective is given effect, and to make any trade-offs clear.

4.10 Before amending the Code, the Authority must comply with section 39 of the Act, which sets out consultation requirements. The consultation under section 39 of the Act will be undertaken at the same time as the consultation on the proposed TPM under clause 12.92 of the Code (see paragraph 4.3 above).

4.11 Under section 54V of the Commerce Act, the Authority must consult with the Commerce Commission before amending the Code in a manner that will, or is likely to, affect the Commerce Commission in the performance of its functions or exercise of its powers under Part 4 of the Commerce Act. The Authority has been liaising with the Commerce Commission throughout its review of the TPM and will formally consult the Commerce Commission before amending the Code.

Obligations under the Code

4.12 As described in paragraphs 4.2 and 4.3 above, the Authority is following the process set out in the Code for reviewing and developing the TPM.

4.13 Because section 38 of the Act provides that, subject to section 39,[64] the Authority may amend the Code at any time, provisions of the Code that purport to elaborate on, or constrain, the Authority's power to amend the TPM are inconsistent with the Authority's discretion to amend the Code. That is because delegated legislation such as the Code can neither extend nor fetter powers conferred by Parliament to amend the Code or the manner in which those powers may be exercised.

4.14 Nevertheless, the Authority is of the view that adopting the process in the Code is consistent with the requirements of the Act.

Consultation charter and the CAPs

4.15 As required by section 41 of the Act, the Authority has developed, issued, and made publicly available a consultation charter that includes guidelines relating to the process for amending the Code, and consulting on proposed amendments.

4.16 The consultation charter includes the Authority's Code amendment principles (CAPs). The CAPs provide guidance about applying the Authority's statutory objective when considering amendments to the Code, and how potential

[64] Section 39 of the Act sets out consultation and other requirements for proposed Code amendments.

amendments to the Code should be assessed, including when the cost-benefit assessment required by the Act is inconclusive.

4.17 This paper does not include drafting to implement a Code amendment. However, because the process set out in this paper may ultimately result in a Code amendment, the Authority is approaching its analysis in a way that is consistent with the requirements of the consultation charter and the CAPs.

Decision-making and economic framework for the TPM

Introduction

4.18 The Authority released a decision-making and economic framework (DME framework) in May 2012. The Authority uses the DME framework to guide its consideration of the problem definition and identification of options to address those problems. However, as stated above, the Authority will also assess options against each limb of the Authority's statutory objective.

4.19 The DME framework sets out the Authority's interpretation of its statutory objective in the context of the TPM. It also sets out a hierarchy of approaches that the Authority will use to identify and assess options for the TPM.

Statutory objective in the context of the TPM

4.20 In the context of transmission pricing, the Authority has interpreted its statutory objective to mean that the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers. This recognises that efficiency and reliability in the electricity industry involve facilitating:

(a) efficient investment in the electricity industry through providing incentives for the right investments to occur at the right time and in the right place. These investments can be in the transmission grid, generation (including distributed generation), distribution networks, or in demand-side management

(b) efficient operation of the transmission grid, generation (including distributed generation), distribution networks, and demand-side management. This means providing incentives for the day-to-day operation of transmission, generation, distribution and demand-side management to involve an efficient trade-off between reliability and cost.

4.21 Efficient investment in the electricity industry primarily relates to dynamic efficiency, while efficient operation primarily relates to static efficiency. The Authority notes in its *Interpretation of the Authority's statutory objective*[65] that, because the Authority's statutory objective requires it to promote the long-term benefit of consumers, the Authority considers that its primary focus is to promote dynamic efficiency in the electricity industry, which includes:

(a) taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in the electricity industry, by both suppliers and consumers

[65] Available at: https://www.ea.govt.nz/about-us/strategic-planning-and-reporting/foundation-documents/.

(b) taking into account the durability of the industry and regulatory arrangements in the face of high impact, low probability events.

4.22 Where a trade-off between static and dynamic efficiency is required, the above statement suggests that preference should be given to the promotion of dynamic efficiency.

Hierarchy of approaches

4.23 The DME framework sets out a hierarchy of approaches that the Authority will use to identify and assess options for the TPM. The Authority prefers options that involve, in order of preference:

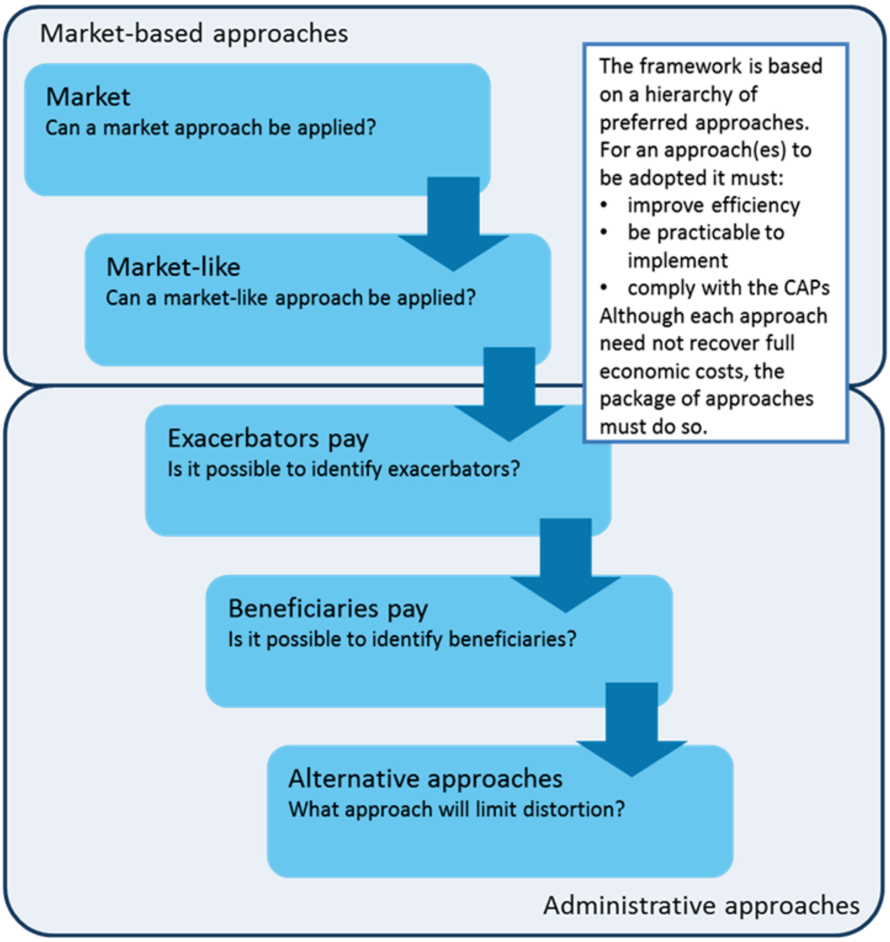
(a) market-based charges

(b) exacerbators pay charges

(c) beneficiaries pay charges

(d) alternative charging options.

Figure 9: DME framework diagram



4.24 The Authority recognises that no method of charging is perfect. The key issue is whether a proposed charging method delivers greater economic benefit than any other practical alternative available. All transmission pricing options involve approximations and trade-offs.

4.25 The Authority also recognises that its statutory objective might best be achieved through a package of charges combining market-based, exacerbators pay, beneficiaries pay and alternative approaches to charging.

Market and market-like charges

4.26 The Authority's first preference is for the TPM to apply a market-based (ie, market or market-like) approach for determining charges.

4.27 A market approach would result in charges established through the interaction of willing buyers and willing sellers in a workably competitive market.

4.28 A workably competitive market tends to be efficient because buyers are free to choose the supplier that best meets their needs, and because, as a consequence, suppliers are encouraged to find the best way to meet buyer requirements. Prices will not exceed the private benefit of a party to the transaction because a willing buyer would not be prepared to complete the transaction if prices exceeded the buyer's private benefit. The main reasons a market approach may not be a viable or efficient approach are that:

(a) there is not workable competition

(b) there are externalities (ie, divergences between private and social costs and benefits)

(c) there is potential for parties to free-ride (ie, opportunities for parties to enjoy benefits without making an appropriate payment), or

(d) because it may impose excessive transaction costs on participants.

4.29 An example of a market is the New Zealand spot electricity market. That market establishes half-hourly prices for electricity through the interaction of willing buyers (ie, electricity retailers and direct consumers) and willing sellers (ie, generators).

4.30 A market-like approach seeks to mimic or replicate the pricing outcomes that would be achieved in a workably competitive market. Prices should not exceed the private benefits to the parties to the transaction. Market-like pricing may be appropriate where there is market failure or where workable competition is not possible.

4.31 The arrangements established by the Code for connection to the transmission grid are an example of a market-like approach. Transpower and the connecting party negotiate the service levels and price of connection (subject to requirements in the Code relating to reliability, and the fact that the Benchmark Agreement applies as a default agreement).

Exacerbators pay

4.32 The Authority's second preference is to apply an exacerbators pay approach.

4.33 An exacerbator in the context of transmission pricing is a party whose act or omission gives rise to a transmission cost. An exacerbators pay approach would address market failures resulting from externalities where transmission costs are not met by the exacerbator, but are instead borne by other transmission customers. If costs arise that are not the result of externalities, beneficiaries pay charging should be preferred.

4.34 An example of an exacerbator in the electricity sector is a direct consumer that uses equipment with a low power factor, resulting in an excessive draw of reactive power from the transmission grid. To address the poor power factor, Transpower might invest in static reactive compensation equipment. If the exacerbator is not required to pay the full cost of that investment, the additional cost will be borne by other grid users.

4.35 Exacerbators pay approaches promote efficiency by making exacerbators face the costs of their actions. A charge calculated using the exacerbators pay approach should reflect the cost, over and above any already committed costs, resulting from an exacerbator's act or omission. Faced with the social cost of its decision, the exacerbator would have appropriate incentives to behave efficiently.

Beneficiaries pay

4.36 When a market, market-like, or exacerbators pay charge is not appropriate or provides insufficient revenue, the Authority's preference is to apply a beneficiaries pay approach. The beneficiaries pay approach involves using a method or methods to determine the parties that benefit from a transmission service. A beneficiaries pay approach may be used to supplement other approaches where that is appropriate. It is most likely to be useful when a workably competitive market cannot be established, but the beneficiaries of a transmission service can be reliably and relatively efficiently identified. Charges to beneficiaries should reflect the lesser of charges that fully recover the costs of the transmission grid being paid for by the beneficiaries, or the anticipated value to them of the services provided by the grid.

4.37 An example of a beneficiary of the transmission grid and transmission services is a direct consumer who benefits from transmission services through obtaining electricity from generators located across the grid and through access to the wholesale market. The consumer may also benefit from grid reactive support services. The benefit the consumer obtains from transmission services may change over time.

4.38 Another example of a beneficiary of the transmission grid and transmission services is a generator that is connected to the grid at a point that is distant from the load it supplies. The generator benefits from transmission services because the generator can transport its electricity and/or access the wholesale market. The benefit the generator obtains from transmission services may also change over time.

Alternative charging options

4.39 An alternative charging option may be needed if a market-based charging approach, or charges based on exacerbators pay or beneficiaries pay, are not efficient, practicable or do not recover the full costs of Transpower's transmission services.

4.40 The Authority considers that the key principles for identifying an alternative charging option that is efficient are that the option should:

(a) minimise, to the extent practicable, any distortion from the efficient level of use of the transmission grid resulting from the imposition of the charge

(b) minimise, to the extent practicable, any distortion in grid-related investment from the efficient level resulting from the imposition of the charge

(c) ensure the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered, as required by the Code.

4.41 An example of an alternative charging option is to use a residual, low-rate, broad-based charge to recover from a large number of parties the costs of maintaining, upgrading, and extending the grid. Such an approach, where the rate of the charge is common to all customers, is often referred to as “postage stamp” pricing.

5 Elaboration of decision-making and economic framework

Introduction

5.1 As set out in chapter 4, in 2012 the Authority developed and published a decision-making and economic framework (DME framework) for the transmission pricing methodology review. The Authority uses the DME framework to guide its consideration of the problem definition and to identify options to address those problems. As set out in the DME framework, in the context of transmission pricing the Authority has interpreted its statutory objective to mean that the TPM should promote overall efficiency. In other words, the TPM should lead to prices that promote efficiency.

5.2 The DME framework sets out a hierarchy of charging approaches. The development of those approaches was underpinned by consideration and analysis of charging for transportation services in workably competitive markets, and drew on contractual economics to explain efficient pricing structures. The hierarchy gives priority to market-based charges where such charges are practicable, because workably competitive markets tend to produce more efficient outcomes than other approaches. If market-based charges are not practicable, the hierarchy gives priority to exacerbators pay, beneficiaries pay, and alternative charging options (in that order).

5.3 Submissions on the options working paper included detailed comments on the efficiency criteria for charging for transmission services and/or critiqued in detail the options proposed by the Authority that were based on the DME framework. This chapter elaborates on the DME framework in light of the Authority's consideration of those submissions.

5.4 The discussion in this chapter is also relevant for distribution pricing, which the Authority has recently consulted on.[66] However, a key difference in the context of transmission pricing is the presence of the spot electricity market, as it produces nodal prices that influence the use of the transmission grid. The absence of nodal prices in most of the distribution sector means the efficient structure of distribution prices could differ materially from the efficient structure for the TPM.

A critical point of difference with some submitters

5.5 This section addresses a critical point of difference with some submissions on various TPM working papers. Some submitters have stated that the Commerce Commission's role in approving Transpower's major grid investment proposals is sufficient to ensure efficient grid investment.[67] In their view there is no need for the TPM to provide price signals to facilitate optimal grid investment since the

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[66] The consultation paper is called "The implications of evolving technologies for pricing of distribution services" and is available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/distribution-pricing-review/consultations/#c15642. The DME framework for distribution pricing is available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/distribution-pricing-review/consultations/#c2072.

[67] For example, Counties Power (p.2-3), Counties Power Consumer Trust (p.1), Pioneer (p.4), Trustpower (p.3).

Commerce Commission will approve investment proposals only when they are efficient. For example, Trustpower suggests that "The IPP has been designed to provide a rigorous process of scrutiny of Transpower's capital expenditure proposals to ensure that they are in the long-term interests of consumers".[68]

5.6 The Authority considers that such submissions do not take into account that the TPM affects demand for the grid (ie, use of the grid), which in turn alters the set of grid investments that are efficient. Even if the Commerce Commission had perfect information and foresight, a TPM that provides inefficient price signals will cause inefficient use of the grid, which will lead the Commerce Commission to approve the set of efficient investments[69] that allow grid users to use the grid inefficiently. In contrast, a TPM that encourages efficient use of the grid will lead the Commission to approve another set of efficient investments that allow grid users to use the grid efficiently. Clearly the latter is more efficient than the former, but the Commission would be prevented from making that decision if the TPM provides the wrong price signals for grid use.

5.7 The Authority has also expressed concerns in previous papers that a TPM that provides inefficient price signals will undermine efficient supply decisions, regardless of the demand issue discussed above. This is because a TPM that provides poor price signals alters the incentives on parties to provide information to, and engage with, the Commerce Commission, harming its ability to effectively test Transpower's proposals against other options.

5.8 The Authority has also argued that a TPM that is fundamentally inconsistent with the principles of efficient pricing is not durable. This is because, as the grid increases in value, charges increase, both raising the stakes for those who believe that the charges they face are not efficient and also increasing the perceived inequities that arise when customers perceive themselves as paying for others' grid access as well as their own. This can be expected to lead to those customers pressing for changes to the TPM to redress such perceived inequities. In addition, more methods for improving the economic efficiency of transmission pricing are becoming feasible over time, which inevitably leads parties to be less accepting of legacy approaches to transmission pricing.

Background on service-based and cost-reflective pricing

5.9 Efficient pricing requires that charges for services are paid by the parties that receive the benefit of those services, and that the charges reflect the full cost of providing the services. That is, efficient prices are service-based and cost-reflective. The prices determined under the existing TPM are neither sufficiently service-based nor sufficiently cost-reflective. It is useful to elaborate on what these terms mean.

5.10 Service-based pricing occurs when the cost of transmission services is charged to, and only to, transmission customers who receive the benefit of those

68 The Commerce Commission will only approve investments for which the projected electricity market benefits exceed the projected electricity market costs (in present value terms), or in the case of investments that are required to meet the grid reliability standards, the least cost option.

69 That is, the investments that are the most efficient possible, conditional on the actual and forecast use of the grid.

services.[70] This means that other transmission customers are not charged for the costs of providing those services. It also means that transmission customers pay higher prices when they receive high service levels and lower prices when they receive low service levels.

5.11 Cost-reflective pricing occurs when the price of a transmission service reflects the full cost of delivering the service. Cost-reflective pricing is desirable because it means the price level signals to transmission users the economic cost of their decisions on the provision of transmission services.

5.12 Service-based and cost-reflective pricing results in prices that tend to adapt to changes in the delivered services and service levels and to changes in the cost of those services/service levels. This is because, if prices are not adaptive, they become misaligned with the delivered services/service levels and misaligned with the costs of those services/service levels. The speed of adaptation depends on a range of factors, including whether the changes in services and costs are temporary or permanent, and how costly it is to change prices (costs associated with changing prices are often called “menu costs”).

5.13 Prices in workably competitive markets tend to be service-based, cost-reflective and readily adaptive. For example, in the spot electricity market in New Zealand, the nodal pricing system is highly service-based and cost-reflective. Nodal pricing rations real-time injections into, and off-takes from, the grid. In effect it levies a “transport charge” on buyers and sellers of electricity in the form of price differences across the grid nodes.

5.14 Those transport charges are highly service-based because they are targeted only to the parties who benefit from transmission services at the nodes with differential prices. The transport charge from nodal pricing is also highly cost-reflective as the level of the charge reflects the marginal cost of using the grid in every half-hour period. With grid conditions changing frequently, the pattern of nodal prices across the grid changes every half-hour, reflecting changes in the cost of using the grid. It is clear from this example that prices that are highly service-based and highly cost-reflective are also highly adaptive.

5.15 As identified in the options working paper, under the current TPM, charges fail to adapt automatically to transmission investment and are not particularly cost-reflective. Adaptability and cost-reflectivity were discussed as separate problems in the options working paper. However, poor adaptability is one way in which prices can become insufficiently cost-reflective. Accordingly, this paper discusses cost-reflectivity and adaptability together.

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[70] Olmos et al suggest that these principles are now widely accepted. They state “By now everybody should agree on some basic sound principles of transmission pricing … the cost of transmission investments should be charged to those network users who benefit from them (since any new transmission facility is built to increase the expected benefits that all network users will globally obtain from the operation of the system with this installed facility) or, equivalently, to those network users who have been responsible for incurring the network investment costs (since the investments are made when they result in total benefits for the network users that exceed the additional transmission costs)”, Olmos, Luis, and Ignacio J. Pérez-Arriaga. "*A comprehensive approach for computation and implementation of efficient electricity transmission network charges*." *Energy Policy* 37.12 (2009): 5285-5295.

5.16 Similarly, the options working paper discussed cost-reflectivity in terms of targeting the cost of particular services to the parties receiving those services. To improve clarity, this paper addresses the targeting issue as part of the service-based pricing discussion.

5.17 With full cost recovery for Transpower, the concepts of targeting costs to those that use the service, and setting the price to reflect the cost of the service, necessarily interact. For example, poor targeting of costs necessarily means poor cost-reflectivity for some that do not receive any benefit from the service, but still bear the costs.

Efficient pricing of dedicated connection services

5.18 From an efficiency perspective, decisions to use the grid should be driven by price signals that are service-based and cost-reflective. To demonstrate this, this paper first discusses the simplest form of transmission service, which is the connection service. The paper then extends this discussion to HVDC and interconnection services (collectively called interconnected grid services in this paper).

5.19 Most connection services are provided to a single connection customer, and, for that reason, are often referred to as dedicated connection services.[71] This section primarily focusses on efficient pricing of dedicated connection services.

Service-based pricing of dedicated connection services

5.20 Connection charges under the current TPM are service-based because the costs of each connection service are charged to the party receiving the benefit of the service.[72] This approach is widely accepted as the efficient approach because it means connection customers face appropriate incentives to:

(d) consider whether the benefit they receive from the connection exceeds the costs they impose on the transmission provider

(e) compare the cost of the connection with the costs of alternatives to connection.

5.21 For example, connection parties have incentives to consider and determine:

(a) *Whether to connect to a local distributor or directly to the national grid*. Facing the full economic cost of each option, the connection customer will contract with the least cost provider. Accordingly, Transpower will only provide the connection service when that option is the lowest economic cost to the country.

(b) *Where on the grid it is best to connect*. As the grid covers a wide range of terrain, some grid locations can be more costly to access than others. It

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[71] There are only a few cases in New Zealand where parties share connection assets. In those cases the connection charges are allocated to them according to their share of anytime maximum demand (AMD) if they are load parties, or their share of anytime maximum injection (AMI) if they are generators.

[72] For the sake of simplicity, the discussion in this section assumes that the costs of each connection are correctly identified and charged to the party receiving the service. Chapter 6 of this paper discusses the Authority's concerns with the current approach of identifying the costs of each connection.

may be cheaper to build a longer connection line to a grid exit/injection point that is relatively easy to access but is further away from the customer's location. Facing the full economic cost of connection incentivises the parties to choose the least cost option for the economy.

(c) *Where to locate their generation or load plant in relation to their connection to the grid*. For example, a run-of-river hydro plant may have multiple locations on a river where it can gain equally good generation performance. Similarly, a commercial consumer may need to use water from a river in its production processes. All other costs being equal, facing the full cost of connection encourages those connection parties to locate at the point of the river that is closest to the grid, as the economic cost is zero for the river to carry the water to the hydro plant or to the consumer’s production plant.

In contrast, transporting coal and gas incurs economic costs. Charging the full cost of connection encourages generators and industrial consumers of coal and gas to optimally trade-off the costs of transporting coal and gas against the cost of connection services. If the transport costs are high, the connection party will locate near the fuel source and pay for a longer connection line to transmit electricity to or from the grid. Conversely, if the transport costs are low then it will locate close to the grid.

(d) *How to charge for sharing the connection asset*. Consider the case where a hydro generator uses a 20km long connection asset running from south (where the hydro scheme is located) to north (where it is connected to the grid). Due to technology developments, wind farms subsequently become commercially viable at several sites along the path of the connection asset, but the addition of the wind farm would require the connection lines to be upgraded. If the wind generator pays only for costs relating to the part of the connection line it uses, then it faces incentives to trade-off any additional costs of upgrading longer lengths of line against the other merits of each site. If all of the feasible sites are equally productive, then it will have an incentive to locate at the site that minimises the cost of connecting to the grid (ie, closest to market). This decision would minimise costs to the economy.

(e) *How much connection redundancy they require*. Facing the full cost of connection encourages connection parties to choose an efficient level of redundancy in the connection assets to cater for the prospect of equipment failure. Connection parties that incur high costs from unexpected loss of electricity supply will either pay the additional costs of duplicate connection assets or choose alternative supply arrangements, whichever is cheaper. For example, Fonterra pays for an onsite backup generator at its Te Rapa milk processing factory because momentary losses of electricity supply are very costly to it (in the form of forgone milk processing).

(f) *How much peak capacity to provide.* Similarly, connection parties face choices about whether to (i) incur the costs of having a very large connection capacity to cover the few times they may want to use the assets to their thermal or voltage limit; or (ii) forgo the benefits of the additional capacity on the few occasions it would be useful; or (iii) invest in alternative options so that they do not have to curtail their production processes. For example, it might be cheaper for an industrial consumer to invest in a small local peaking generation plant to supplement the electricity supply from connection assets for the few times a year the additional energy is needed.

(g) *When to replace or augment the connection assets*. A lot of technological advances occur over the life of a connection asset. For example, costs have been reducing rapidly for evolving technologies such as small scale solar and wind generation, home storage systems, and consumer tools and apps for managing electricity flows. Micro grids[73] appear to be growing rapidly, and very remote consumers are increasingly deciding to install self-generation systems with a minimal backup connection to local networks. These changes potentially alter the optimal date for replacing or augmenting assets.

Facing the full cost of replacing connection assets encourages connection parties to replace their existing assets only if the benefits they derive exceed the costs, and if the replacement is cheaper than alternative solutions. For example, connection parties will have an incentive to compare the full capital and maintenance costs of a replacement asset against the cost of maintaining the existing asset, and will have an incentive to replace the asset only when the former is less than the latter.

5.22 All of the above choices involve substantial resource costs, and in total could materially affect the productive and dynamic efficiency of the electricity system.

5.23 In contrast, if the costs of an individual connection were shared across all connection parties (rather than each connection party paying the costs of the connection services delivered to it), that would undermine productive and dynamic efficiency.

5.24 For example, suppose a connection party accounted for 1% of Transpower's total connection charges. If its connection costs were spread across all connection parties, it would effectively remove all incentives for the party to make efficient decisions in regard to the choices in paragraph 5.21. For every choice it faced, the connection customer would pay only 1 cent in the dollar of the actual costs involved. It would not have the incentive to critically assess the alternative of where to connect to the grid. It would have the incentive to locate close to the source of other inputs (eg, coal or gas) irrespective of how costly that made connection to the grid. And it would have the incentive to seek a very high level of connection capacity with maximum redundancy built in.

Setting cost-reflective prices for dedicated connection services

5.25 The previous section discussed the efficiency rationale for service-based pricing of connection assets. This section discusses the key characteristics of cost-reflective prices.

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73 A micro grid is a localised grouping of electricity sources and loads that normally operate connected to and synchronous with the traditional centralised grid (macro grid), but can disconnect and function autonomously as physical and/or economic conditions dictate. A micro grid generally operates while connected to the grid, but it can break-off and operate on its own using local generation in times of crisis like a power outage, or for other reasons. See www.energy.gov/articles/how-microgrids-work.

5.26 The efficient price is easy to determine when connection assets exhibit constant returns to scale (CRS).[74] In this case, the efficient price is the short-run marginal cost (SRMC) of the service. SRMC is the cost of producing an extra unit of a good or service whenever desired. Often this is when one or more inputs, such as the amount of capacity, cannot be altered over short intervals. This contrasts with the long-run marginal cost (LRMC) of the service, which is the cost of producing an extra unit of a good or service when all inputs can be altered optimally.

5.27 Under CRS conditions, LRMC = SRMC because the cost per unit of additional capacity is the same no matter how big the expansion. This means that output and all production inputs (including physical capital) can be varied by infinitely small amounts at any time. As both types of marginal cost are equal in this case we simply refer to marginal costs (MC).

5.28 Under CRS the average cost (AC) of the service equals the marginal cost of the service.[75] This condition means that charging prices equal to SRMC raises sufficient revenue to cover total costs, including a normal return on capital.

5.29 However, investment in connection assets typically exhibit large economies of scale.[76] The efficient approach in this case is to charge the full cost of connection assets by:

(a) charging a maintenance fee based on the actual amount of maintenance work undertaken on the connection asset. In practice, the fee would be charged monthly, as a flat $/month rate

(b) charging for capital costs on a $/year basis. The size of the charge depends on the capital outlay on the connection assets, on their depreciation rate and on the provider's cost of capital.

5.30 The $/year charge is an access fee unrelated to use. In return for paying for the capital cost of the connection assets, the connection party has the right to use as much of the asset as it wishes, as often as it wishes, provided it complies with contractual terms, such as safety, operating and resource management requirements.

5.31 The bulk of the maintenance fee is also an access fee because the maintenance requirements for connection assets are typically driven by environmental conditions, such as the degree of salt spray or tree growth etc., rather than by usage.

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[74] Constant returns to scale occurs when increasing all inputs in a production process by m% produces an m% increase in output. This contrasts with increasing returns to scale (often called economies of scale), where an m% increase in all inputs increases output by x%, where x > m. Large economies of scale are where x/m is large. In effect, constant returns to scale is where there are no economies of scale at all (ie, where x = m).

[75] To see this, let the total cost of supplying quantity q be a CRS function such as $TC(q) = c.q$, where c is a constant. Then the average cost is $AC = TC/q = c$, and the marginal cost, $MC = TC(q+1) – TC(q) = c$.

[76] That is, the average unit cost of output decreases as output increases. For example, installing an 11kV transformer once costs substantially less than installing eleven 1kV transformers, with the installations occurring over many years as the need for additional capacity evolves. See footnote 77 for a formal definition of economies of scale.

5.32 The day-to-day costs of using connection assets fall directly on users of the connection service, rather than on the provider of the connection service. One of the usage costs arises from losses of electrical energy on the connection assets. For a grid user that buys electricity at the point of connection to the grid (ie, through the nodal spot market), any energy lost as it is transported over connection assets is a cost to that grid user. Similarly, a generator (including distributed generation) that sells its electricity at grid injection points bears the cost of any energy lost on transporting its electricity over the connection assets. Hence, the user of the connection service faces an implicit usage price equal to the SRMC of losses.

5.33 An efficient connection pricing regime in the context of large economies of scale has a two-part pricing structure:

(a) an explicit access price, which is comprised of the capital and maintenance fees described above

(b) an implicit usage price, which is the SRMC of losses.

5.34 This is efficient because it is service-based and cost-reflective, and so creates the desirable incentives discussed above.

The efficient timing of investment when there are large economies of scale

5.35 When there are large economies of scale in investment, small increments in capacity are uneconomic. Hence, 'step changes' are made in connection capacity at infrequent intervals rather than continuous small changes at the margin. This means there needs to be a focus on incremental costs and benefits, not just marginal costs and benefits.

5.36 In the discussion below, C denotes the present value of the cost of an efficient increment in connection capacity. The economic cost of permanently increasing peak use by one unit (for example 1MW) is that it increases energy losses on the connection assets and it brings forward the timing for the next capacity expansion. Hence, the cost of a permanent increase in peak use equals the SRMC of losses plus the additional cost of spending C earlier than would occur otherwise. This is called the marginal incremental cost (MIC) of grid use, or more simply the marginal cost of bringing forward an investment by a period of time such as a year.[77]

5.37 Large economies of scale in investment also mean that connection parties rationally forgo benefits from expanding connection capacity by self-rationing their peak use of the assets until the benefits from bringing forward an efficiently-sized investment are large enough to justify the MIC of that investment.[78]

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[77] For example, MIC = SRMC + additional interest costs etc of bringing forward an investment by a year. The full cost of the investment, C, is not included in MIC but the interest cost on C is included. A detailed description of MIC was provided in Transmission Pricing Methodology: Long Run Marginal Cost (LRMC) Charges working paper, which is available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c13677.

[78] As is discussed later in this chapter under the heading *Efficient pricing for interconnected grid services,* if the investment is justified by losses and constraints, and the user pays nodal prices, then the nodal price signals the incremental benefit of the investment and no self-rationing is necessary.

Looking at it another way, the connection party acts as if it faces a price for use of the asset high enough to ration its peak use of the asset to the capacity available. This implicit price is often called the "shadow" price or the short run marginal opportunity cost (SRMOC). It is the cost that they face as a result of using less capacity than they would use if surplus capacity was available.[79]

5.38 In the discussion below, B denotes the present value of benefits the connection party would gain from an efficient increment in connection capacity. In other words, B is the present value of all direct costs and opportunity costs the connection party would not incur if connection capacity was expanded by an efficient amount.

5.39 In simple situations where B and C can be estimated with a high degree of confidence, it is efficient to increase connection capacity when two conditions hold:

(a) B exceeds C. This is just the standard economic cost-benefit result that, when there is perfect certainty about costs and benefits, investments are economic when the net present value (NPV) of the investment is positive.[80]

(b) Investing later would result in marginal benefits in the interim exceeding marginal costs in the interim. That is, investing at any later time would result in the present value of SRMOC during the period of delay exceeding the present value of MIC during the period of delay.

5.40 In a business with growing peak use of connection assets, connection parties continually evaluate whether to expand capacity. Expanding too early results in B<C or in situations where some net benefits are unnecessarily forgone. Connection parties maximise their net benefits by having Transpower expand capacity when the two conditions in the previous paragraph hold.

5.41 Thus, even though a decision to expand capacity results in a step change in capacity, the decision about when to expand capacity is evaluated continuously and is a marginal (timing) decision. That is, shall we spend C today or tomorrow?

Charging the full cost of connection services encourages efficient timing of investment

5.42 The access fee outlined in paragraph 5.33 encourages efficient investment decisions by connection parties. By adopting a regime under which connection parties pay the full cost of their connection services, they also pay the full cost of increments in their capacity. This ensures that they consider the incremental

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79 The term "opportunity cost" is an economic concept which Wikipedia defines as follows: "the opportunity cost of a choice is the value of the best alternative forgone, where a choice needs to be made between several mutually exclusive alternatives given limited resources". The term is used here because the customer forgoes production that would have been profitable if there had been sufficient capacity to provide electricity at the SRMC at the customer's connection point.

80 This investment rule has to be amended to include a real option value when the following three conditions hold: (1) there is uncertainty about C or B, (2) investment is irreversible to some degree, and (3) waiting may reveal whether the investment will pay off. In this case the investment rule has to be amended and results in NPV > 0. Including real option valuation in the investment rule does not alter the broad conclusions in this paper. Because of this, we assume the real option value is zero in what follows.

costs they impose on the economy from decisions they make about their use of, and additional investment in, connection assets.

5.43 Although each dedicated connection party is only charged for connection investments after they occur, they know the connection charging regime will result in them paying the full costs of expanding the connection capacity serving them. Connection parties will therefore anticipate future connection charges when making decisions that increase, or are intended to increase, their peak use of the assets, such as decisions to increase their generation or load capacity.

5.44 In effect, by continually evaluating when to expand capacity, and anticipating the additional charges it will face, a connection party makes decisions taking into account an implicit SRMOC charge. This means that there is no value to be gained from the connection provider setting an explicit SRMOC charge prior to expanding connection capacity. This conclusion does not necessarily apply, however, when considering the efficient pricing of interconnected grid services, discussed further below.[81]

Efficient access pricing for shared connection services

5.45 The above discussion focusses on dedicated connection services where there is only one connection customer receiving each connection service. There are some situations, however, where two or more parties share the use of connection assets and so share the connection services provided by those assets.

5.46 The previous discussion referred to incremental costs as the cost of increasing capacity by an efficient increment. The definition of incremental cost (IC) is more subtle when a service is shared by multiple parties. In these cases, incremental costs are the additional costs of providing a customer or group of customers with new or additional services.[82]

5.47 There are also often common costs when a service is shared by parties. Common costs are costs that are not attributable to any one customer or group of customers. If consideration is being given to a single user of a shared service, then the common cost of the service equals the total cost of providing the service minus the incremental cost of providing the service to the single user.[83]

5.48 It is useful to compare incremental costs with standalone costs (SAC). SAC is the total cost of providing transmission services or equivalent alternative services to the customer or group of customers. Standalone costs are usually estimated

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81 The key factor in this conclusion is that there is only one user of each connection asset, which is the case for the dedicated connection services discussed in this section. In this case, the connection party knows that its decisions in regard to peak use of the connection service solely determine the timing of future capacity increments. As is discussed later in this chapter, nodal prices in the spot market play a key role in regard to the conclusions about the need for SRMOC signals for interconnected grid services.

82 It is important to realise that IC is very different from SRMC and variable cost. IC includes fixed capital costs whereas SRMC and variable cost do not. Also, different ICs are obtained depending on whether the situation under consideration is the additional cost to serve one more customer versus the additional cost to serve a subset of customers.

83 But if the discussion is about a subgroup of customers sharing a service, then the common cost of the service equals the total cost of providing the service minus the incremental cost of providing the service to that group. If the discussion is about all customers sharing the service then incremental costs equal total costs and the common costs of the service are zero.

by considering the costs of a purpose-built transmission facility or alternative facility to suit the needs of the customer(s).

5.49 In situations where sharing of services leads to common costs, charging every customer the standalone cost of the service they benefit from would raise more revenue than is needed to fund the full cost of the asset. Accordingly, charges to each customer can be reduced to cover a portion of common costs, provided each customer is charged at least the incremental cost their use imposes.

5.50 In particular:

(a) provided the charges are not below IC then customers have incentives to take into account the additional costs they impose on Transpower

(b) provided the charges do not exceed the customer's SAC then the customer has incentives to share the assets rather than build their own or bypass the assets with an alternative project.

5.51 As a result, charges in the range between IC and SAC are consistent with grid customers making efficient production and investment decisions. A corollary of the above pricing principle is often used to define cross-subsidies—that is, where one user of a shared asset is subsidising another user. The economics literature defines a cross-subsidy to be where one of the users pays charges below IC.

5.52 The Authority considers that the TPM should avoid situations where charges for shared connection assets are above standalone cost or below incremental cost.

5.53 Where there is more than one user of a connection asset, there is often considerable margin between the sum of IC and the sum of SAC across all customers using the shared connection asset. This leaves considerable scope to vary the charges particular users face while ensuring that the charges collectively meet the efficiency criteria in paragraph 5.50 and while also recovering the full cost[84] of the asset.

5.54 In this circumstance, it is desirable to share the charges among different users roughly in proportion to the benefit that they receive from using the asset. If each user pays in proportion to the benefit they receive, then no user will pay more than the benefit they receive unless, collectively, the benefits of the investment are less than its full cost; that is, unless the investment is inefficient and should not proceed.

5.55 This principle of charging users according to their share of the benefit is consistent with what happens in a market transaction between a willing buyer (or willing buyers) and a willing seller. The former will have an incentive to pay the cost of an asset if and only if the total benefit they receive from the asset is at least its full cost. If the benefit to the buyer is not at least the full cost of the asset, the most efficient outcome is for the transaction not to proceed.

5.56 Similarly, if there is more than one user of a connection asset, and the users of the asset are charged in proportion to the benefit they receive from using the

[84] In the rest of this document, we use "full cost" of any investment used by any group of grid users to mean the total incremental cost of that investment. Cost-reflective pricing requires that, collectively, all users who benefit from an investment collectively pay just the full cost of the investment.

asset, the users of the asset will have the incentive to seek installation of the asset if and only if the collective benefit they receive from the asset exceeds its cost. Thus charging users in proportion to the benefit they receive from the asset ensures that they are encouraged to support installation of the asset if and only if it is efficient to do so. If users are charged on any other basis, it would leave open the possibility that one or more users would be charged more for the asset than the benefit they derive from it, even though the collective benefit exceeds its cost.[85]

Moving from connection services to interconnected grid services

5.57 The preceding section has discussed the logic of charging for connection services. The same logic also applies to charges for interconnected grid services — ie, for HVDC and interconnection services—which we discuss further below.

5.58 For a dedicated connection service, it is obvious who receives the benefit of the service, and if there is any disagreement, withdrawing the service is a feasible option and will reveal who is receiving the benefit of the service.

5.59 In contrast, determining who benefits from services from the various components of the existing interconnected grid is not so obvious. In principle, the benefits of the services provided by the interconnected grid reflect the portfolio of assets comprising the grid, rather than any one asset. The interconnectedness of the grid means that it also provides backup services that benefit load parties (consumers and distributors) and some types of generation, such as generators using non-controllable sources of fuel (eg, geothermal, wind and solar). The interconnected grid also enables competition between generators supplying the grid, including generators supplying the grid via local distribution networks. Greater competition among generators benefits consumers.

5.60 There are a variety of methods of approximating grid use and benefits.[86] One method of approximating who benefits from grid services involves using flow tracing techniques to model power flows. This technique was used to determine the application of the deeper connection charge discussed in the options working paper. In effect, the beneficiaries of the services of individual components of the

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[85] To be clear, this principle of charging users in proportion to their share of the benefits is entirely consistent with the Authority's DME framework. For example, the Authority's document *Decision making and economic framework for transmission pricing methodology: Decisions and reasons* states at paragraph 35 that "The Authority's interpretation of its statutory objective takes a net-benefits approach to determining efficiency". In particular, the market-based, exacerbators pay, and beneficiaries pay approaches are all consistent with it. For example, a market-based approach involves a voluntary exchange, which ensures that a customer has the incentive to contract for use of an asset if and only if the benefit it derives from the asset exceeds the cost.

The reason that the Authority prioritises the approaches (in the order market-based, exacerbators pay, and beneficiaries pay) is that those ranked higher in the Authority's hierarchy are more market-like, in the sense that they devolve to market participants the authority and responsibility for making (and modifying) the investment and charging decisions, as opposed to these being administratively determined. Those ranked higher are therefore more likely to promote ongoing efficiency gains.

[86] Perez-Arriaga (ed.), pp 299-307, gives a useful discussion of these issues: Pérez-Arriaga, Ignacio J. *Regulation of the power sector*. Springer Science & Business Media, 2014.

interconnected grid were deemed to be the parties receiving power flows over those assets.

5.61 In reality, the actions of any one grid user spill-over to the power flows for other grid users, with effects akin to the way a set of marbles move in a pipe. The lower the impedance of the grid assets (or friction in the case of marbles), the stronger and further the spill-over ripples across the grid. The well-known 'loop flow' effects are one type of spill-over in electricity grids. The spill-over effects are imperceptible in regard to the action of any one small user but they are very noticeable in regard to large participants such as generators and industrial consumers, and in regard to aggregations of small users acting in concert.

5.62 In addition, due to the laws of physics, the benefits of interconnectedness come at the "cost" of generators losing control over the direction by which their energy injections "travel" over the grid. Similarly, grid users are unable to direct that their energy off-takes derive from certain sources of energy or take certain paths over the grid to reach them. This means that grid users are unable to choose whether to use specific interconnected grid assets.[87]

5.63 For example, suppose that flow tracing showed that historically the energy injected by a generator located in Taranaki rippled out over the North Island interconnection system, and only about 10% of it flowed over the HVDC during dry winter seasons. Now suppose that another party builds generation just north of Hamilton and begins injecting into the system during dry winter seasons. This activity alters power flows across the grid. It could reorient the power flow of the Taranaki generator so that 50% of its energy flows over the HVDC during dry winter seasons. Flow tracing would then assign a higher proportion of the HVDC costs to the Taranaki generator even if it had not altered its offer behaviour.

5.64 The use of nodal pricing for the spot electricity market creates a financial analogue to these physical spill-overs. That is, the action of any one grid user alters the pattern of nodal prices across the grid, although some of these actions have imperceptible effects. Augmenting the grid in one location can ripple across the entire grid, creating financial benefits (and dis-benefits) for many different parties.

5.65 These considerations illustrate why power flows across the interconnected grid can be problematic for determining who benefits from interconnected grid services.

5.66 Bringing these considerations together, a service-based approach to interconnected grid services can be approached directly through identification of the beneficiaries of interconnected grid services or indirectly through flow tracing.

(a) Assessing the benefits directly (for example, through a market model) can provide a good measure of the actual benefits users receive. In particular it deals well with the financial spill-over effects of grid investments, which are often quite large and widespread. It is far easier to adopt this direct approach for new grid investments than for existing investments because

[87] It also means that the uncoordinated actions of grid users can "crash" the system. Hence, a system operator is used to ensure real-time operation of the interconnected system performs to acceptable levels.

assessing how much each party benefits from a new investment can be integrated into the determination of the total economic benefits of the investment (the latter has to be done anyway to determine whether to proceed with the investment). There is often no record of the estimated benefits for many existing assets used to provide interconnected grid services.

(b) Actual use of the grid is often adopted as a proxy for assessing the benefits derived from use of grid services. For example, flow tracing assumes that the flows of electricity that a user ''causes" reflects the benefits they receive. Flow tracing does a good job of measuring the benefit of grid services to particular grid users where there are limited physical and financial spill-over effects— ie, in the more remote parts of the grid and for small areas of the grid that have minimal price effects through-out the rest of the interconnected grid. It can also be readily applied to existing assets.

Efficient pricing for interconnected grid services

5.67 In principle, the rationale for service-based and cost-reflective pricing applies to interconnected grid services as equally as it does to connection services. A service-based approach charges grid users only for the benefit they receive from grid services. A cost-reflective approach sets prices based on the full cost of delivering the service.

5.68 As is discussed above, a key difference between connection services and interconnected grid services is that connection services typically benefit a dedicated user or very few users, whereas typically there are many users sharing interconnected grid services. This sharing of services is coordinated by New Zealand's nodal-based spot electricity market, which rations use of the grid on a half-hourly basis.[88]

Transport charges arising from the nodal spot market

5.69 Having a well-functioning nodal spot market is important for efficiently pricing use of the interconnected grid, and in particular for providing an efficient price signal to encourage grid users to take into account the implications of their grid use decisions for the timing of future grid upgrades. Due to their very large cost, the efficient timing of grid investments yields significant net economic benefits for electricity consumers.

5.70 The nodal spot market produces prices for energy at injection and offtake nodes. These are usage prices (as distinct from access prices). Provided the nodal spot market is workably competitive, and there are no significant externalities, these prices are reasonably efficient for coordinating use of the existing interconnected grid. This is because the prices reflect reasonably well the SRMC of using the interconnected grid.

5.71 Whereas usage prices for connection services are implicit prices, the nodal spot market provides explicit usage prices. The difference in the price at one node versus another represents an explicit price for using the circuit between the two

[88] Actually, generation is often dispatched on five-minute intervals.

nodes. Therefore, under competitive conditions, the usage prices for transporting electricity from one part of the interconnected grid to another are reasonably efficient.

5.72 In effect, the nodal spot market produces a "transport charge" for a grid circuit that is low when there is spare capacity on the circuit, and high when the circuit's constraints bind.[89] As is explained in the box below, this transport charge arises from losses, grid constraints and circuit outages. The transport charge rises as losses on the circuit increase and as circuit constraints bind more frequently and/or for longer durations. It also rises if the marginal cost of generation downstream of the circuit constraint increases relative to the marginal costs of generation upstream of the constraint.

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[89] As is discussed earlier, a similar rationing process occurs in relation to using connection capacity, but it occurs as a result of connection parties self-rationing their peak use of connection assets. In this case connection parties face an implicit usage price, the SRMOC, analogous to the explicit usage fees produced by the spot market for the grid.

5.73 Generally, all three factors (losses, constraints and generation costs) increase as peak use of a circuit increases. So the transport charge for the circuit rises over time prior to expansion of the circuit (or expansion of another circuit that reduces energy flows on the circuit). The transport charge will typically vary widely around a rising trend, reaching very low values during off-peak periods or when power flows on other circuits relieve pressure on the circuit.

5.74 Let MB denote the marginal benefit of expanding the circuit this year rather than next year. This equals the present value over the year of (a) reductions in the cost of energy losses, (b) reductions in the use of expensive generation, and (c) reductions in forgone consumption of energy due to better reliability of the grid. Note that each unit of forgone energy is valued at the relevant VoLL.

5.75 Let MB_N denote the marginal benefit of expanding circuit capacity that is reflected in nodal prices. As spot market prices can be well below VoLL when there is a forced reduction in energy consumption (see discussion in the box), we can have situations where $MB_N < MB$.[93] That is, the marginal benefits reflected in spot

SRMC of using a circuit

There are three components to the SRMC of using a circuit:

(a) the marginal cost of losses, denoted $SRMC_L$

(b) the additional marginal cost of using costly downstream generation rather than cheaper upstream generation, denoted $SRMC_C$

(c) the marginal value of forgone grid supplied electricity when a circuit trips that leaves a consumer without grid supplied electricity, which is often called the marginal value of lost load and denoted VoLL.[90]

The SRMC of using a grid circuit equals $SRMC_L$ when security constraints on the circuit are not binding and equals $SRMC_L$ + $SRMC_C$ when circuit constraints are binding. The SRMC equals VoLL when the circuit fails completely and no grid power is supplied to the consumer.[91] The efficiency of spot market prices is reduced when:

1) there is weak competition resulting in nodal prices of grid use exceeding SRMC or

2) consumers' power supply is interrupted, as nodal prices are usually far below VoLL in those cases (unless an administered scarcity price reflecting estimates of VoLL is adopted).[92]

90 The Code uses and defines the term for VOLL (expected unserved energy) and specifies a value ($20,000 per MWh) for the value of the expected unserved energy. Note that VoLL is a particular type of SRMOC that was discussed earlier in this chapter in regard to the pricing of dedicated connection services.

91 In some cases, consumers have backup sources of energy, such as a standby gas peaker plant, in which case VoLL equals the short-run marginal cost of the backup energy source. Increasingly residential consumers are investing in household solar generation for their primary source of energy supply and using the grid as a backup source of energy.

92 The NZ electricity market has an administered scarcity price for Island or nationwide supply interruptions.

93 In general, the spot price does not include the VoLL for practical reasons: the VoLL will vary by node and by each customer at each node. It would, however, be possible to include an approximation to VoLL in nodal prices. The NZ electricity market has an administered scarcity price for Island or nationwide supply interruptions.

prices can be less than the true marginal benefits. On the other hand, weak competitive pressure in the spot market may result in spot prices exceeding marginal costs at times, and could push the spot market marginal benefits higher than MB (ie, MB_N > MB).

Efficient expansion of interconnected grid circuits

5.76 In the same way as explained for connection services in paragraph 5.39, it is efficient to expand circuit capacity or replace an existing circuit when two conditions hold:

(a) The present value of the economic benefits (B) exceeds the present value of economic costs (C)—ie, when B exceeds C. This is, in essence, the investment approval test in the Capex IM used to assess Transpower's proposals for major grid investments (other than major investments in the core grid).[94]

(b) Investing later would result in marginal benefits in the interim exceeding marginal costs in the interim. That is, investing at any later time would result in the present value of SRMOC during the period of delay exceeding the present value of MIC during the period of delay.

5.77 Suppose the Commerce Commission approves grid investments when the two conditions in the previous paragraph hold. If MB_N (ie, the marginal economic benefits reflected in nodal prices) approximately equals MB, then the transport charge inherent in nodal prices provides price signals that encourage grid users to take into account the impact of their grid use on the timing of grid investments. In particular, the transport charge from the spot market should approach the marginal incremental cost of the corresponding amount of grid capacity in the years immediately before grid expansion is due to occur.[95]

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94 The core grid is specified in Schedule 12.2 of the Code. The investment test for core grid investments permits approval of an investment where expected net electricity market benefit is not positive (ie, permits approval of an investment with the lowest expected net electricity market cost).

95 Under certain simplifying assumptions (including that the loss and constraint excess is increasing continuously over time), the savings signalled by the *immediate* change in nodal price as a result of an increase in grid capacity will be very close to the MIC of that capacity at the time that investment in the grid is justified. This is because the benefit of investing this year rather than next year is the loss and constraint excess saved over the year as a result of the investment. The loss and constraint excess for subsequent years is saved whether we invest this year or next. Similarly, the cost of investing this year rather than next is just the cost of capital for the year on the investment and its annual depreciation and maintenance cost. The capital, depreciation and maintenance costs for subsequent years are approximately the same whether we invest this year or next. Thus, the net benefit of investing this year rather than next is positive if the LCE saved over the year exceeds the MIC of the investment. (For simplicity, the impact of bringing forward the investment on the need to bring forward subsequent investments is ignored. This can be justified by the assumption that each investment has a very long life).

An implication of this is that the net present value of an investment is likely to be strictly positive at the time the investment just becomes justified. This is because the investment test is based on the savings in LCE this year compared with the cost this year, while the net present value includes future annual savings in LCE, which are larger than the current year savings in LCE because of load growth. Consistent with this, the Commerce Commission is required to ensure that the investment option chosen has the highest expected net electricity market benefit.

Clearly, the addition of forward markets with transparent pricing has the potential to improve signalling of the benefits of grid expansion.

5.78 This conclusion depends, however, on the assumption that other prices affecting grid use are efficient.[96] These other prices include the explicit charges in the TPM, including the RCPD component of the interconnection charge, and the HAMI/SIMI components of the HVDC charge.

5.79 The importance of this caveat is that the Commerce Commission's assessment of B depends on the change in grid use that will occur in the future as a result of an increment in grid capacity, which in turn depends on these other prices (eg, RCPD and HAMI/SIMI-based charges). If these other prices provide incentives for inefficient use of the grid, then the Commerce Commission's investment approval rule will lead to the Commerce Commission approving efficient grid investments[97] to provide for inefficient use of the grid. This means, in an overall sense, the grid investment will almost certainly be inefficient.[98] Investment decisions made by grid users, such as their decisions about where to locate their assets and what energy sources to use, are also likely to be inefficient.

Using the TPM to promote efficient grid use and investment

5.80 In the Authority's view, nodal prices provide relatively good incentives for efficient use of the grid as the spot electricity market is workably competitive the vast majority of the time, trading conduct rules have been adopted for the few periods when a generator is pivotal and VoLL pricing (also called scarcity pricing) has been adopted for periods when there are nationwide or island-wide losses of supply to consumers. Hence, the rest of this section elaborates on ways to structure the TPM to promote efficient use of, and investment in, the interconnected grid.

The transport charge from nodal pricing is insufficient to fully fund grid investment

5.81 Nodal prices generate a financial surplus in the spot market. In simple terms, the surplus on a circuit in any trading period equals the difference in prices between the two nodes of the circuit during the trading period multiplied by the amount of energy that flows between the two nodes during the trading period. These surpluses are used to create a pool of funds called the loss and constraint excess (LCE).

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96 Economists will recognise this argument is an example from general equilibrium welfare theory. See *The General Theory of Second Best* R. G. Lipsey and Kelvin Lancaster, The Review of Economic Studies Vol. 24, No. 1 (1956–1957), pp. 11-32.

97 That is, the grid investment is efficient, if we take as given the actual and forecast use of the grid.

98 One way to think about this is to let P_T denote TPM prices, P_N denote nodal prices, $U(P_T, P_N)$ denotes grid use that occurs as a result of those prices and let grid capacity be denoted as K(U). That is, grid capacity is a function of grid use. Let * denote efficient prices and outcome variables. Assume nodal prices are efficient—that is, assume P^*_N. Then an inefficient P_T implies an inefficient U which then implies inefficient K. More formally, if P_T is structured inefficiently then we get $U^*=U(P_T, P^*_N)$ and therefore $K^*=K(U^*)$. On the other hand, if P_T is structured efficiently such that it equals P^*_T then we get $U^{**}=U(P^*_T, P^*_N)$ and therefore $K^{**}=K(U^{**})$. By definition, K** is a more efficient level of grid capacity than K*. K* is efficient given U*, but it's not globally efficient. In other words, the investment approval rule applied by the Commerce Commission only ensures efficient grid investment for whatever U is. Decisions about the TPM affect U and therefore affect K. Getting TPM price structures more efficient will assist the Commerce Commission to consider applications for approval for K**.

5.82 A well-established result in the economics literature is that setting prices equal to SRMC yields insufficient revenue to cover a firm's total costs if its production and investment processes exhibit economies of scale.[99]

5.83 Thus, in the context of provision of interconnected grid services, this implies the differences in nodal prices (which often equal differences in SRMC) will yield insufficient LCE to fully fund interconnected grid services, and it will be necessary to supplement the LCE with revenue from transmission charges. This shortfall will be increased if grid investments are undertaken to meet regulated reliability standards, rather than being justified only by the economic benefits of the investment. The shortfall will also be increased if grid investments are undertaken earlier than would strictly be efficient due to biases in the investment approval process.[100] In practice, the LCE from the HVDC and interconnection assets in New Zealand typically provides no more than 20%–30% of the cost of providing those assets.

5.84 Hence, as for connection services, efficient pricing of interconnected grid services is likely to require a two-part tariff of the following form:

(a) Usage prices, such as the "transport charges" produced by the nodal spot market. Alternatively, if nodal pricing was considered to be deficient and unable to be remedied through reforms to spot market pricing rules, then explicit usage fees could be adopted in the TPM to limit grid use to the available capacity until additional investment in capacity is justified.[101]

(b) Access prices, which are charges allocated to grid users in ways that are not directly related to the extent of their grid use.[102] These could include charges allocated on the basis of the physical capacity of grid users[103] or on the basis of the expected benefits they receive from using the grid.

Step 1: Usage and access charges in the TPM should promote efficient grid use

5.85 From an allocative efficiency perspective, the theoretically most efficient approach to raising sufficient revenue to fund interconnected grid services is to leave nodal pricing to provide all of the usage pricing for each grid circuit, and set 'lump sum' access prices for each circuit to cover the revenue deficit from nodal

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[99] Although not discussed earlier, this result also applies for connection services if they exhibit economies of scale. Paragraph 5.28 shows that MC = AC when production processes exhibit constant returns to scale. Let P denote the implicit usage price and let Q denote usage. With P=MC=AC, the firm's total revenue (which is P x Q) equals total cost (which is AC x Q). By the definition of economies of scale, MC < AC. Hence, P=MC means P<AC and therefore P x Q < AC x Q. The revenue deficit on connection assets would equal (P – AC) x Q if access fees were not charged.

[100] These biases could arise, for example, because poor price signals cause inefficient participation in decision-making processes. This is discussed further in Chapter 6.

[101] This could be desirable, for example, if the potential grid investment would be triggered by breaching of a reliability standard rather than by losses and constraints. The efficient approach in this case is to set the TPM usage fees equal to the SRMOC of using the grid for those trading periods for which nodal pricing was deficient.

[102] Note that access prices will affect grid use but they are not a usage charge. Usage prices are charges levied on the amount of use of the grid—ie, the more you use the more you pay.

[103] Note, however, that this might affect use by affecting installed capacity.

pricing.[104] A 'lump sum' access price or charge is one that is allocated on the basis of factors that grid users cannot alter, and accordingly a 'lump sum' charge does not alter behaviour.

5.86 In reality, any access charge will likely alter customers' choices about grid use to some extent, so the goal is to set an access charge that limits allocative inefficiency. Similarly, setting explicit usage charges in the TPM to fully fund the interconnected grid would also distort customer choices and cause allocative inefficiencies. For example, the TPM could impose a margin on differences in nodal prices to drive total usage prices above the marginal costs of using each grid circuit. But this pricing regime would discourage grid use compared with a regime in which usage prices equalled the SRMC of using the interconnected grid, causing some allocative inefficiency.

5.87 In principle, if 'lump sum' charges are not feasible, the most allocatively efficient approach is to set combinations of access and usage charges for each grid circuit that reflect the relative price elasticities of demand across the activities affected by the two sorts of charges.[105] As nodal pricing provides reasonably good incentives for efficient use of the grid, any charges in the TPM should, at the very least, be designed to avoid unnecessarily undermining the incentives created by nodal pricing.

5.88 It is possible, although unlikely, that alternative types of usage charges, such as ones that use peak demand or peak injection to gather revenue, may also be relatively efficient allocatively. Like access charges, these charges create incentives to distort use, but they broaden the revenue base. In principle, the key issue is whether the revenue they raise allows other distorting TPM charges to be reduced such that the total of allocative inefficiencies are minimised.

5.89 In addition to these considerations, economic analysis suggests that it could be allocatively efficient to set different charges on different grid users, or groups of grid users, depending on their price elasticities of demand (this approach is called Ramsey pricing). In principle, Ramsey pricing could be applied to both access and user charges. However, a strict Ramsey pricing approach is not feasible in the context of transmission pricing.[106]

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[104] This result is qualified once dynamic efficiency considerations are introduced. See the discussion at paragraph 5.91.

[105] See Laffont &Tirole (1994), p.145-9, for a mathematical proof of this statement. This proof assumes that it is necessary to raise the full cost of production from users, but does not take account of the impact of mispricing of investment on the dynamic efficiency of future investment. This extension is covered in paragraph 5.91.

[106] Setting TPM charges in strict accordance with Ramsey pricing requirements would be very informationally-demanding, and no country has adopted Ramsey pricing where it would be theoretically justified. The widely-held view of tax and regulatory policymakers around the world is that attempting to set prices in strict accordance with Ramsey pricing requirements would (1) incur very high administration costs and (2) could in practice result in a set of charges that deviate further from allocative efficiency than more straightforward allocation options. In addition to the inefficiencies noted in (1) and (2) above, Ramsey pricing would result in very high prices on parties that have highly inelastic demand, such as hospitals, which many people may see as inappropriate. To the extent the consequences arising from applying Ramsey pricing to recover the costs of transmission services reduced the durability of the TPM, they cause dynamic inefficiencies. Note the proposal in chapter 7 of this paper rejects the strict Ramsey approach but it does give some consideration to Ramsey pricing principles in regard to formulating a prudent discount policy.

5.90 In summary, it is efficient to use access charges to recover some of the costs of Transpower's services. It is desirable to set those charges taking into account their impact on grid use relative to the impact of alternative charging options.

Step 2: Productive and dynamic efficiency need to be taken into account in determining the efficient combination of usage and access charges in the TPM

5.91 The above discussion abstracts from the need for access charges to promote efficient investment. As with connection parties, creating efficient investment incentives requires that parties receiving particular grid services face the full costs of delivering those services to them.[107] This is because firms make production and investment decisions based on the relative private benefits and costs of the choices available to them.

5.92 For example, suppose generators face the choice of paying either zero charges for interconnection services, or the full costs of alternatives that deliver services of equivalent value to them, such as gas transmission. Generators would have an incentive to demand electricity transmission in circumstances when it is more costly to the economy than the alternatives.

5.93 The underlying reason for this is that both services deliver equivalent benefits for the grid user. Not being required to pay for accessing one source of those benefits inevitably creates incentives to shift production and investment towards use of that source. Conversely, if parties have to pay for services they do not receive (by paying a higher rate for their other services) then their production and investment decisions are distorted in the other direction. Paying for the full costs of a service—and no more—is a fundamental principle for promoting productive and dynamic efficiency.

5.94 Failure to adhere to these pricing principles encourages grid users to make inefficient choices analogous to the matters referred to in paragraph 5.21 above for connection services. Such productive and dynamic inefficiencies are typically far more costly than the allocative inefficiencies discussed earlier regarding Ramsey pricing and optimal two-part tariffs (see paragraphs 5.85 to 5.90).

5.95 Importantly, as is discussed in paragraph 5.79 above, the choices made as a result of these inefficiencies affect the way that parties use the grid, which flow into inefficient type, levels and timing of grid investment. This result applies to major capex investments that are subject to Commerce Commission approval and to base capex decisions if those decisions are based on NPV criteria.

5.96 The need for access charges to promote efficient investment means that the charges discussed in paragraphs 5.85 to 5.90 must be modified to ensure that users face the full cost of the grid services from which they benefit. In other words, achieving dynamic efficiency comes at the expense of some loss in allocative efficiency. Specifically, to the extent practicable, users must face access charges that are service-based and cost-reflective, while taking into

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[107] As stated in paragraph 5.53 that we are intending the term "full cost" principle to include the incremental/standalone pricing principle.

account the principles in paragraphs 5.85 to 5.90 to ensure that the loss of allocative efficiency is limited.

Transitional issues

5.97 Implicitly, the above discussion applies to investments that are made after the date of the introduction of the new TPM. As many submissions have noted, service-based and cost-reflective pricing cannot alter investment decisions about historical investments. As a result, the dynamic efficiency gains from applying such pricing to historical assets are restricted to future modifications of those assets, and so are much weaker than implied in paragraphs 5.91 to 5.96 above. Arguably, therefore, in these circumstances a stronger emphasis should be placed on allocative efficiency, and so a greater focus on approximations to 'lump sum' charges for recovering the cost of those investments.

5.98 Nevertheless, the Authority is of the view that there are good reasons to apply service-based and cost-reflective pricing approaches to recent major historical investments as well as future investments. These are as follows:

(a) Time consistency. Applying the same regime to recent major historical assets will provide a clear signal that the Authority expects that regime to apply in future, and so reinforce market participants' expectations that they will pay service-based and cost-reflective prices for future investments.

(b) Perceptions of fairness (durability). Market participants typically regard it as fair and reasonable that they pay the cost of services they benefit from. However, they do not regard it as fair that they pay both that cost (for new investments) and the cost of services used by others for historical investments through regimes like postage stamp pricing. Accordingly, such a mixed regime is unlikely to be durable.

A regime that applies service-based and cost-reflective pricing both for future investments and recent major historical investments will increase the extent to which market participants will pay for assets they use and decrease the extent to which they pay for assets that others use. This is likely to be much more durable.

(c) Allocative efficiency. Applying service-based and cost-reflective pricing to historical assets will entail some loss of allocative efficiency, compared with closer approximations to 'lump sum' pricing, as discussed earlier. However, if, as is intended, access charges are charged on a basis that is relatively unrelated to the SRMC of use, they should have little impact on use and so the loss of allocative efficiency is likely to be small.[108]

5.99 Thus, although a narrow interpretation of efficiency would suggest that market participants should pay only incremental costs for existing assets, the Authority is of the view that a broader interpretation of efficiency is likely to warrant the

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[108] For example, Perez-Arriaga (ed.), pp 306-308 proposes that the access fee for each user be based on historical use, and charged as a user-specific lump sum dollar fee. If this were feasible, it would avoid most of the allocative efficiency costs of cost-reflective prices. Pérez-Arriaga, Ignacio J., *Regulation of the power sector*, Springer Science & Business Media, 2014.

application of service-based and cost-reflective pricing to both new and recent major historical assets.

Applying service-based and cost-reflective pricing in practice

5.100 Both connection and interconnected grid services exhibit significant economies of scale, which gives rise to the need for charges over and above the SRMC of using the service. The key difference between the two services is that the assets used to provide interconnected grid services are used by many users, making it necessary to find some way to attribute the cost of those services to the particular grid users that benefit from particular parts of the interconnected grid. However, the underlying economic imperative for service-based and cost-reflective pricing remains equally valid for interconnected grid services as it is for connection services.

5.101 Under the service-based approach, a methodology is required to assess the benefits that various parties receive from various components of the interconnected grid. It then becomes a relatively straightforward exercise to allocate access charges to grid users in accordance with those metrics. The methodology is not required to be perfect. It only needs to achieve better efficiency outcomes than possible alternatives (including the postage stamp approach). Specifically, the efficiency gains from the methodology should more than offset the higher transaction costs of developing and administering the methodology, and any higher compliance costs for grid customers.

5.102 In practice, there are significant costs involved in administering the TPM and costs for transmission customers in verifying that they are being charged in accordance with the methodology. Customers also incur resource costs both in changing their use of the grid, and also changing the way their use is measured without significantly changing their actual use,[109] so as to avoid TPM charges. Collectively, these costs are referred to as transaction costs.

5.103 If there are high transaction costs associated with each type of charge, it may be efficient to adopt a small number of less efficient charges that simplify the TPM.

Summary

5.104 In summary, encouraging efficient grid investment requires service-based and cost-reflective charging for both new and existing grid investments. This requires charges for grid services to be based on a two-part tariff structure, comprising a usage charge based on the short run marginal cost of grid use and an access charge that is largely unrelated to use but which reflects the full costs of investment. In practice, overall efficiency means that these requirements need to be balanced against the requirement to avoid excessive transactions costs.

[109] One example of such behaviour under the current TPM is the actions of some customers to reduce their use to zero at the time of RCPD.

6 Problem definition: does the current TPM promote overall efficiency?

Introduction

6.1 This chapter sets out the Authority's problem definition for its review of the TPM. It is a refinement of previous work the Authority has done on the problem definition and takes into account submissions made about the problem definition.[110]

6.2 The problems are described in relation to the TPM, including amendments to the TPM that have or will be made as a result of Transpower's operational review. Unless otherwise stated, the Authority's discussion assumes that the changes to the TPM arising from Transpower's operational review have been implemented (even though those changes do not come into force until 1 April 2017). Those changes are expected to result in increased efficiency compared with the TPM currently in force.

6.3 Unless the context otherwise requires, in this chapter and in subsequent chapters, a reference to the current TPM or the status quo TPM is a reference to the TPM as amended as a result of Transpower's operational review. Likewise, references to the current connection charge, interconnection charge, and HVDC charge are references to those charges as amended (or affected) by changes made as a result of Transpower's operational review.

6.4 At a high level, the Authority's view of the problems with the TPM is that it does not promote the long-term benefit of consumers, because:

(a) it does not promote efficient investment in the transmission grid, generation and distribution, and efficient investment by electricity consumers, and

(b) it does not promote efficient operation of the transmission grid, generation, distribution, and demand-side management.

6.5 This chapter discusses the problems that the Authority has identified in relation to the following matters:

(a) HVDC and interconnection charges

(b) connection charges

(c) prudent discount policy

(d) the allocation of LCE

(e) the recovery of the costs of network reactive support.

[110] This takes account of submissions on the TPM options working paper, as well as previous articulations of the problem definition. They include submissions stating there are no problems with the current TPM or that the problem definition has not progressed. For example, see the following submissions on the TPM options working paper: AECT (p.1), Northpower (p.3), TLC (p.7), ENA (p.12), Orion (p.3-4), Powerco (p.2), Trustpower (p.11-12), PwC (p.5), Counties Power Consumer Trust (p.2).

Problems with HVDC and interconnection charges

6.6 The Authority is of the view that, in relation to HVDC and interconnection charges, there are three main problems with the TPM:

(a) *Poor price signals are incentivising inefficient use of interconnected grid assets, inefficient investment in interconnected grid assets, and inefficient investment by grid users*: The current HVDC and interconnection charges are not sufficiently service-based or cost-reflective and so the charges send poor price signals for use of the interconnected grid, which affects a wide range of investment decisions.

(b) *Poor price signals are incentivising inefficient participation in investment decision-making for the interconnected grid, which leads to inefficient grid investment decisions*. The current HVDC and interconnection charges are not sufficiently service-based or cost-reflective and so:

(i) Participants are incentivised to pursue investments for the interconnected grid that provide net private benefits to those benefiting from the investment but are not efficient overall. This arises because the current charges mean participants either contribute little compared with the benefit received or do not have to contribute.

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

(c) *Poor durability.* The HVDC and interconnection charges are so poorly service-based or cost-reflective that they harm the durability of the current TPM. Poor durability exacerbates long-term uncertainties, potentially causing users of the interconnected grid to make inefficient location and investment decisions. It can also waste resources by creating incentives for lobbying for variations to the TPM that would not occur with an efficient TPM.

Poor price signals are incentivising inefficient investment and inefficient use of the interconnected grid

6.7 As is discussed in the previous chapter, prices that are service-based and cost-reflective provide grid users with incentives to locate efficiently in relation to the grid and provide incentives for them to efficiently trade-off grid costs against the cost of alternatives to grid services. These incentives are essential to encourage efficient investment in and use of the interconnected grid and efficient investment by grid users.

6.8 The previous chapter explained that, in principle,[111] the nodal spot market produces an implicit transport charge for each grid circuit. This charge reflects

[111] In practice, most users of grid services do not face the nodal price, because retail electricity charges typically do not have a use charge that varies in real time. As technologies change and retail competition increases, a shift towards more real time pricing is likely. This is because market pressures will undermine the profits of retailers who cross-subsidise those who use high cost electricity by overcharging those who use low cost electricity. One

the SRMC of using each circuit on the interconnected grid. Hence, the nodal spot market provides transport charges that correspond to the marginal cost of using each part of the interconnected grid. In particular, as discussed in paragraph 5.72, the transport charge for each grid circuit increases as the circuit becomes more congested (prior to expansion of the circuit or expansion of another circuit that affects energy flows on the circuit). Nodal price differences reduce sharply immediately after an expansion has occurred.

6.9 As nodal prices reflect SRMC reasonably well, service-based and cost-reflective pricing requires that the cost of investments in the interconnected grid be recovered from those who benefit from those investments, in ways that minimise any further impact on use of the interconnected grid.

6.10 The current HVDC and interconnection charges are not service-based or cost-reflective. This section discusses how this incentivises inefficient use of, and investment in, the interconnected grid, and inefficient investment by grid users.

Inefficiencies in investment caused by the HVDC Charge

6.11 The HVDC charge creates inefficient incentives to locate generation in the North Island. This is because the HVDC charge is paid solely by South Island generators. Other parties also receive services and benefits from the HVDC but pay no HVDC charges. For example, Transpower's North Island load customers receive services from the HVDC when the power flows northwards over the HVDC, and North Island consumers receive the benefits of those services. Similarly, North Island generators and South Island load customers receive services/benefits when the power flows southwards over the HVDC.

6.12 Transpower estimated that, if the HVDC charge had been applied in the 2014/15 pricing year on a SIMI basis, the charge would have been $7.14/MWh.[112] The average wholesale price for Benmore for the period 1 April 2014 to 31 March 2015 was $69.43/MWh. This means the HVDC charge (based on SIMI) for 2014/15 would have been about 10 per cent of the average Benmore wholesale price. This implies the HVDC charge, and in particular the requirement under the current guidelines that it is applied only to South Island generators, is still likely to have a substantial effect on the operation of, and investment in, South Island generation.

Inefficiencies in investment caused by the interconnection charge

6.13 Conversely, the interconnection charge provides inefficiently weak incentives for optimally locating generation and load around the interconnected grid. This is because the requirement under the current guidelines that the interconnection charge must be a postage stamp on load customers means:

(a) generators do not pay any charge for interconnection services, despite clearly receiving services and benefits from interconnection circuits

sign of this may be the recent entry of Flick Electric into the electricity retail market which charges users spot market prices.

112 Refer to the following presentation available on Transpower's website: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Scientia-Consulting-HVDC-report.pdf (p.10).

(b) as a "postage stamp" charge it does not vary in accordance with the benefit load customers derive from access to interconnection services.

Inefficiencies caused by generators not paying interconnection charges

6.14 In relation to paragraph 6.13(a), generators clearly receive services from the Wairakei Ring, for example, as it was built in part to allow new geothermal generation in that area to transport electricity to the wider interconnected grid. As the current TPM imposes no interconnection charges on generators, it has potentially encouraged generators to develop generation options around the Wairakei Ring ahead of other options that would have involved substantial connection charges but lower overall economic costs.

6.15 If New Zealand Aluminium Smelters (NZAS) decides in the future to close its aluminium smelter at Tiwai, then the interconnected grid in the lower South Island (LSI) would need to be augmented so that surplus power from the deep south could flow north. Under the current TPM, however, generators in the LSI would face none of the additional costs of those augmentations. This means that they are incentivised to develop new generation options in the LSI[113] without taking into account the additional costs that additional interconnection investments would impose on the economy.

6.16 Similarly, a generator has an incentive to locate a new gas-fired plant in Taranaki, close to the source of gas, even if the overall cost of locating elsewhere is less. This is because it must pay a distance-related access fee and transport fee for transporting gas, but it pays zero interconnection charge for transporting electricity to consumers.

6.17 The above are just three examples. There are approximately 60 power stations directly connected to the national grid. This means there have been many production and investment choices in the past that could potentially have been affected by the fact that generators do not pay interconnection charges.[114]

Inefficiencies caused by load paying a postage stamp interconnection charge

6.18 Load customers pay the interconnection charge. As it is a "postage stamp" charge it does not vary in accordance with the benefit that load customers (including load customers of a distributor, when the distributor passes on the interconnection charges) derive from the interconnection services that they pay for. The result is that it provides these parties with no incentive to take into account interconnection charges when they make decisions on where they locate their businesses.

6.19 For example, industrial consumers face broadly the same interconnection charge regardless of where they are located. This incentivises them to locate their industrial plants close to the sources of their other inputs and the destination of their outputs to minimise the costs of transporting their inputs.

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[113] At least to the extent that they have incentives to do this after taking into account the disincentive provided by the HVDC charge described in the previous section.

[114] The inefficient incentives resulting from the fact that generators do not pay interconnection charges also potentially apply to distributed generators as they would not pay interconnection charges even if there is net injection from the node at which they are located.

6.20 The current interconnection charge also creates similarly poor incentives for distributors to minimise economic costs. For example, Westpower is the local distributor for Greymouth and surrounding region. It accounted for 0.3% of Transpower's interconnection charges in 2014/15. The requirement under the guidelines to spread all interconnection costs across all interconnection parties leaves Westpower paying 3 cents in every 10 dollars for any interconnection assets built in its area. This greatly reduces incentives for Westpower to make low-cost decisions on anything that could substitute for interconnection assets. Instead, Westpower is incentivised to encourage Transpower to build interconnection assets in the area.

6.21 The existing guidelines encourage Transpower to consider levying the interconnection charge on a peak basis.[115] Since the interconnection charge is levied according to a load customer's RCPD, this means there is an uneven incidence of the charge across the four charging regions in New Zealand. As a result, interconnection charges are sometimes lower for regions far from large sources of generation than for regions where the generation is located. This is shown in figure 10 below, which is a heat map of interconnection charges in $/MWh across the country. On this measure, Northland consumers pay a lower interconnection charge than consumers in the Waitaki and Taranaki regions.[116] Under service-based and cost-reflective pricing, the opposite would be expected since the transmission costs involved in transporting power to distant regions are much greater than to regions in which generation is located.

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[115] In particular, paragraphs 13 and 14 of the guidelines state:

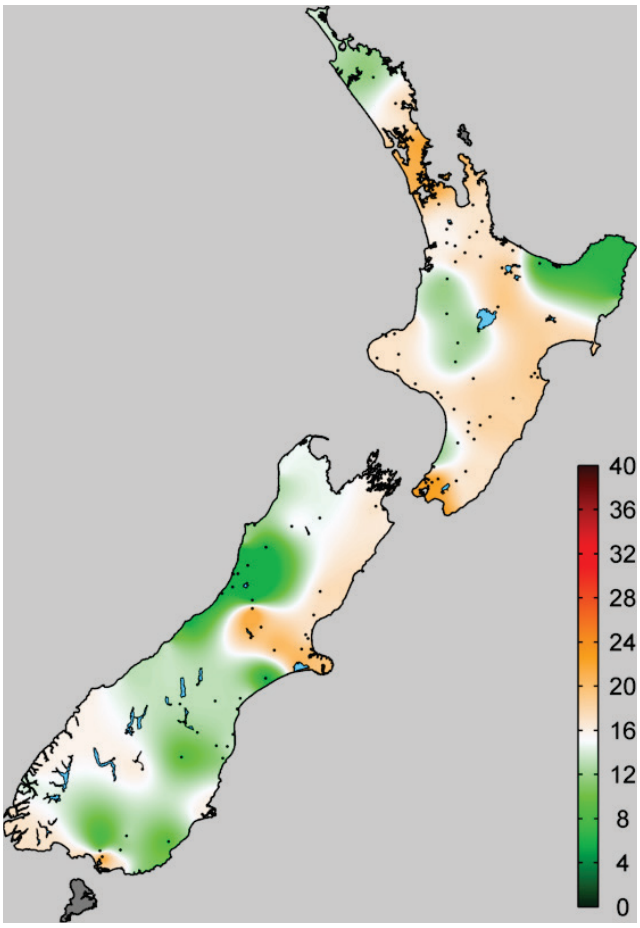
"13 Transpower should review the existing basis on which it calculates the interconnection charge at a grid exit point. Specifically, Transpower should review whether using the 12 highest half-hour offtake peaks in the 12 months up to and including the current month is most consistent with the Pricing Principles in rule 2. This review includes consideration of anytime versus regional or national coincident peaks.

"14 Transpower should also review whether permitting greater aggregation across GXP loads for the purpose of calculating interconnection charges to encourage peak load management within regions would produce prices more consistent with the Pricing Principles in rule 2."

Electricity Commission, Guidelines for Transpower, Transmission Pricing Methodology, 24 March 2006.

[116] Strictly, most consumers don't actually pay the interconnection charge. It is paid by designated transmission customers. However, if the charge is passed directly through distributors and retailers to consumers, then the effect is the same as if consumers actually paid the charge.

Figure 10: Current TPM charges for distributors in fully variabilised terms ($/MWh)[117]



6.22 The postage stamp requirement for the interconnection charge is also detrimental to dynamic efficiency. In particular, it hinders low growth regions by requiring them to effectively fund fast growing regions. For example, transmission charges have increased significantly over the last five years for transmission customers to fund growth in the Auckland region.[118]

The TPM encourages inefficient grid use and so inefficient investment

6.23 As is noted above, nodal prices encourage efficient use of the interconnected grid. Service-based and cost-reflective pricing requires that the cost of investments in the interconnected grid to be recovered from those who benefit from them, and that the charges to be structured in ways that minimise any further impact on use of the interconnected grid.

6.24 In contrast, the interconnection and HVDC charges are both based on the use of assets to which the charges relate. In broad terms, the RCPD allocator for the interconnection charge is based on a measure of peak use, as is the HAMI allocator for the HVDC charge. The SIMI allocator for the HVDC charge—which

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[117] The figures in this chart are for the case where generators do not pass on transmission charges.

[118] Refer to paragraph 6.49(b).

is being phased in progressively as HAMI is phased out from 1 April 2017—is based on a measure of average use.

6.25 This encourages inefficiently low use of the interconnected grid generally. Specific aspects of the charges also cause specific distortions in use, as is discussed in the rest of this section.

The TPM discourages grid use after investment increases capacity

6.26 The TPM inefficiently discourages use of the interconnected grid after an investment to increase the capacity of the interconnected grid.

6.27 As noted above, the marginal cost of using the interconnected grid rises as circuits become increasingly congested, and steps down sharply when the capacity of the interconnected grid is expanded.

6.28 The interconnection and HVDC charges calculated under the current TPM undermine the (efficient) incentives created by nodal prices. When new investments are commissioned, their costs are added to the revenue to be recovered. Similarly, replacements to interconnected grid assets add to the revenue requirement when, as is currently the case, historical assets are valued at depreciated historical cost. In relation to both the HVDC and interconnection charges, usage charges rise just as the marginal cost of using the relevant circuits steps down sharply.

6.29 This shows that the current TPM undermines the signal provided by nodal prices. It discourages use of the interconnected grid immediately after an investment occurs, which is when there is spare capacity and the cost of using the interconnected grid should be low. This encourages electricity consumers and generators to forgo economically beneficial opportunities to use the interconnected grid. This clearly undermines efficient use of the interconnected grid.

6.30 This is illustrated by the increase in charges for the use of the HVDC and relevant interconnection assets that resulted after investment in those assets was made.

6.31 Transpower identified in its operational review that the interconnection charge, if it was calculated using 100 periods (N=100),[119] would have increased from $1,241/MWh in 2008/9 to $2,312/MWh in 2014/15.[120] This represents an 86 per cent increase.[121]

6.32 In the TPM operational review Transpower also identified that, following the HVDC upgrade, the HVDC charge increased from $25.25/kW in 2008/09 to

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119 This is the number of periods used to calculate the interconnection charge in all regions following Transpower's TPM operational review.

120 Refer Figure 3, Page 16, Transpower TPM operational review, Appendix B: Background and supporting information. The calculations are in 2014/15 dollars.

121 Note that while Transpower refers to this as a 54 per cent increase, Transpower's reference refers to the proportion of the price in 2008/09 compared to the price in 2014/15.

$44.60/kW in 2014/15.[122] This represents a 77 per cent increase in the charge.[123]

6.33 Transpower's operational review resulted in a change to the basis on which the HVDC charge is to be calculated from historical anytime maximum injection (HAMI) to mean injection from South Island generation (SIMI) over the previous five capacity measurement periods.

6.34 In terms of the problem discussed here, the effect of introducing the SIMI-based HVDC charge is to dilute the strength of the inefficient signal given by the HVDC charge. This is because the price signal from the charge is potentially spread over 17,520 trading periods (the number of trading periods in 12 months, which is a capacity measurement period) and is further diluted by the fact that the charge is calculated using a 5-year rolling average.

6.35 On the other hand, the move from the HAMI allocator to the SIMI allocator does little to improve the price signal when HVDC capacity is expanded. The SIMI use-based charge is still very likely to increase after expansion of the HVDC when the marginal cost of using the HVDC is reduced. However, the rate of the SIMI charge is lower than the rate of the HAMI charge, and so any misalignment between the usage charge and SRMC is likely to be less costly than for the HAMI charge.

The TPM inefficiently discourages grid use at peak periods

6.36 The interconnection charge for a transmission customer is based on the customer's use of the interconnected grid (excluding the HVDC link) that coincides with the occurrence of the 100 highest regional peak demand periods in a year. This distorts the signal provided by nodal prices during these periods. It encourages grid users to suppress their demand for grid-supplied electricity when there is no economic benefit from doing so.[124] This leads them to inefficiently forgo consumption of electricity in those periods or, if they have their own generation, to use their own generation to maintain their consumption in those periods even when it costs more than it costs Transpower for them to use the grid.

6.37 Further, the high usage charges during these periods may encourage grid users to inefficiently install their own distributed generation. Similarly, the charges may encourage grid users to inefficiently invest in demand response capability to suppress their demand when the charges are high.

6.38 There are more than 160 power stations connected to local networks or embedded networks. The operation of those power stations—and decisions to build, retire, or upgrade them—are potentially affected by the RCPD-based

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[122] Refer Figure 4, Page 17, Transpower TPM operational review, Appendix B: Background and supporting information.

[123] The Transpower document identifies this as an approximately 60 per cent increase in the HVDC rate but that is the proportion of the rate in 2008/09 to the rate in 2014/15.

[124] If distributors pass the charge directly on to their customers, then those customers are encouraged to suppress their demand. However, as many distributors are owned by consumer trusts, they may also be encouraged to suppress demand on their network.

interconnection charge. This is because each distributor[125] faces incentives to build or contract for generation in the distributor's network if the generation can be operated during regional peak demand periods so as to reduce the distributor's coincident peaks and therefore avoid RCPD-based interconnection charges.

6.39 The same issues do not arise with regard to the SIMI-based HVDC charge. The SIMI allocator produces a reasonably constant rate of usage charge.[126] In effect, the SIMI charge is a low-rate broad-based charge on South Island generators. It imposes a relatively uniform (but still inefficient) distortion to the signal provided by nodal prices.

Inefficient grid use encourages inefficient investment

6.40 The previous two sub-sections explain why interconnection charges encourage inefficient use of the interconnected grid. Transpower seeks approval for investments in the interconnected grid based on its forecasts for what use of the interconnected grid will actually be. The result is that even if Transpower makes the most efficient investment possible for a given use of the interconnected grid, the investment will be inefficient because use of the interconnected grid is inefficient.

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

6.42 It is difficult to quantify the size of these problems, since it would require comparing actual investment with what investment and use would have been had charges for the interconnected grid been service-based and cost-reflective. Nevertheless, the incentives which create the inefficiencies are clear.

Summary: Poor price signals are causing inefficient grid use and inefficient investment

6.43 In summary, prices are service-based and cost-reflective if the main parties who will use an investment (and not parties who do not) collectively pay for it in accordance with the benefits they receive. Ensuring that the prices charged for grid investment are service-based and cost-reflective ensures that all parties have the incentive to seek investment when and only when it is efficient. No other form of charging for grid investment achieves that.

6.44 Setting prices that are not aligned with the services customers receive from a grid investment is a concern because it undermines incentives for efficient investment in many ways. For example, if grid users do not have to bear the full cost of an investment in the interconnected grid, they will be incentivised to:

(a) seek to have an investment in the interconnected grid undertaken before it is efficient

[125] Note these incentives are transferred to the distributed generation (DG) owner if the distributor pays ACOT to the DG owner.

[126] This is not the case for the HAMI charge for the HVDC, which is being phased out over a four year period.

(b) undertake associated investments in generation or load when it is not the lowest cost option for the economy

(c) locate their investments in generation and load in places where they can minimise their investment in connection assets, even if the cost of the interconnected grid assets they use instead is greater

(d) undertake investment in generation plant fuelled by gas in places close to the source of the gas (because they have to pay the full price of gas transmission), even when it is more efficient for them to locate nearer the load and further from the source of gas

(e) rely on distributed generation, even when direct generation is lower cost to the economy.

6.45 Many of these inefficiencies would occur even if Transpower's forward-looking investment analysis turns out to be entirely correct (that is, even the best possible investment analysis will not avoid the above inefficiencies). That is because Transpower must respond to investment in generation and load undertaken independently by grid users. Those investment decisions are affected by the prices grid users actually pay for grid services. To the extent that those prices are not service-based and cost-reflective, this will incentivise decisions that will not be aligned with the overall efficient level of investment.

6.46 The Authority commissioned a cost-benefit analysis which estimates the cost of these inefficiencies for generation. This is discussed in chapter 8. The inefficient incentives on load are also clear, but estimating their impact in practice is a lot harder. To identify them, the Authority would need to know what each grid user would have done had it faced the full cost of the associated grid service. To do this, the Authority would need to know what options were available to the grid user when it undertook the investment, and what the relative profitability would have been had they faced their share of the cost of the grid. This is unlikely to be practical.

Charges for recent investments are not service-based or cost-reflective

6.47 This section analyses the impact of large post-2004 grid upgrades. It shows that the charges that followed these investments are not service-based and are not cost-reflective.

6.48 Four of the largest post-2004 grid upgrades—the North Island Grid Upgrade (NIGU), the North Auckland and Northland grid (NAaN) upgrade, the Otahuhu substation diversity project, and the upper North Island (UNI) reactive support project—were principally undertaken 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.

6.49 More than $1.3 billion of grid investment has been made in the UNI since 2004. This accounts for 29 percent of Transpower’s RAB of $4.61 billion in 2015/16, or 48 percent of approved grid investment (including HVDC) since 2004.

(a) The grid investment translates to an increase in Transpower’s RAB and consequently the revenue required to be recovered under the TPM. The increase is approximately $221 million per annum. Of this, only $87 million or 39 percent is paid for through an increase in charges to UNI. Transmission charges for customers in the LNI, USI and LSI have increased by 61 percent, on average, largely to pay for the cost of investment in the UNI which largely serves to improve transmission service levels to Auckland, in particular.

(b) The relationship between investment in different regions and transmission charges is illustrated in Table 3 below.

Table 3: Incidence and allocation of post-2004 approved investment

Region	Post-2004 investment*	Impact on Transpower revenue requirement	Actual increase in interconnection charges from 2008/9 to 2015/16	Actual tariff increase as a % of impact on revenue requirement
UNI	$1.342m	$201m	$87m	43%
LNI	$237m	$36m	$80m	225%
USI	$77m	$12m	$40m	343%
LSI	$81m	$12m	$40m	327%

*does not include HVDC or connection investment

6.50 The difference between interconnection charges in the North and South Island relative to asset value in these two regions is growing.

6.51 Transpower has noted that “Current allocations between the North Island and South Island, under the RCPD charge, are 66% and 34% respectively”.[127] The Authority has compared the current allocation of interconnection charges to each island with the book value of the interconnected grid (excluding the HVDC link) in each Island. On this analysis, the Authority estimates the book value of the North Island grid represents 79% of interconnection assets, and the South Island, 21%. The Authority has also compared the allocation of interconnection charges to each Island to the estimated replacement cost of the grid in each Island. On this analysis, the Authority calculated that the estimated replacement cost of the North Island grid represents 73% of interconnection assets and the South Island 27%.

6.52 This analysis suggests that, under postage stamp pricing, interconnection charges for load in the South Island are relatively high as a percentage of the installed asset base in that island compared with the North Island. Likewise, the change in interconnection charges for load in the South Island as a result of the new investment is relatively high as a percentage of the size of the new investments there compared with the North Island.

[127] The allocation of interconnection charges was 65% and 35% for the North Island and South Island respectively in the 2008/9 pricing year and remained effectively unchanged at 66% and 34% respectively for the 2014/15 pricing year. Refer to Transpower’s document (p.6) available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Additional%20component%20-%20RCPD%20quantity%20adjustment%20provision.pdf.

6.53 The projections for regional development and population growth in Auckland versus the rest of the country suggest the imbalance identified above is likely to increase in future.

6.54 The Authority does not consider that it is efficient for other regions to meet the costs of growth in Auckland, or equivalently for the UNI region transmission charges to increase by less than the cost of transmission investment driven by UNI demand. The impact on transmission pricing for other regions has already been substantial. Subsidisation in growing regions can be expected to artificially stimulate greater growth and investment in growing regions, putting further pressure on infrastructure and stimulating greater investment requirements, at the expense of other regions.

Consideration of submissions and the Authority's response

6.55 A number of parties that submitted on the options working paper submitted that they agreed with the Authority's problem definition as set out in that paper.[128] For example, Alliance Group submitted that Otago/Southland businesses and consumers are being overcharged by $64 million per annum under the current TPM. Meridian submitted that the HVDC allocation of costs is an example of a cost-reflectivity problem.[129] Transpower (CEG), although not substantively supportive of the Authority's problem definition, submitted that a disparity between benefits and charges can lead to the following:

(a) customers will make sub-optimal investment decisions that impact adversely upon Transpower's investment costs, harming dynamic efficiency

(b) parties will alter their grid usage in undesirable ways to avoid those outlays, reducing static efficiency.[130]

6.56 Unison submitted that it "experienced in excess of $10 million per annum of increased transmission interconnection charges, but has seen little evidence to support that consumers in Unison's regions have received benefits".[131]

6.57 New Zealand Aluminium Smelters (NZAS) submitted that "NZAS was built to make use of an excellent hydroelectric resource at Manapouri which was too large for any anticipated local load. NZAS was later expanded to facilitate the development of the Clyde dam. Hence, NZAS was located in its current position to allow for port access and to minimise the need for transmission. With a high load factor, NZAS is an ideal transmission customer as the transmission assets are continuously utilised. Auckland, by comparison, grew organically because of the natural advantages the location has for residential living. These advantages

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[128] For example, Alliance Group (p.2), Community Trust of Southland (p.2), Dongwha New Zealand (p.2), EIS (p.2), E-Type Engineering (p.2), Export Southland (p.2), Federated Farmers Southland (p.3), HW Richardson (p.2), Invercargill Licensing Trust (p.2), JK's & Wbe (p.2), Lewis Windows (p.2), Market South (p.2), McIntyre Dick and Partners (p.2), Otago Chamber of Commerce (p.2), Preston Russell Law (p. 1), Queenstown Chamber of Commerce (p.2), Ms Dowie MP (p.1), SBS (p.2), South Port NZ (p.3), Southern Institute of Technology (p.2), Southland Manufacturers Trust (p.1), Southland region (p.1), Stabicraft (p.2), Venture Southland (p.1), Powernet (p.2), TNT2 (p.2), NZAS (p.19), WPI (p.1).

[129] Meridian (p.1).

[130] Transpower (CEG) (p.3).

[131] Unison (p.3).

did not include nearby economic energy resources. As a result considerable expense has been, and continues to be, applied to transporting electricity to Auckland. With a large residential base, Auckland demand is 'peaky' and the transmission capacity built to supply Auckland is only fully utilised for small proportions of a year. Because of these characteristics, the economic cost of providing transmission services for NZAS is considerably lower than the economic cost of transmission to Auckland".[132]

6.58 Buller Electricity Limited (Buller) submitted that current charges may lead to a cross-subsidy in the future. Buller noted that "the landscape is changing as a consequence of new technologies which threaten to reduce this [standalone] cost. Therefore it is of increasing importance to have transparency and cost-reflectivity in transmission charges so that investment in transmission alternatives can be assessed efficiently. Buller considers the economic efficiency argument to be less about cross subsidies, and more about signalling the potential over-recovery of standalone costs".[133]

6.59 However, some submitters did not agree with the Authority's problem definition in relation to cost-reflectivity. For example, the Auckland Chamber of Commerce submitted that: "The Chamber's understanding of the current approach of charging a flat-rate across the country for the shared national grid appears to work well".[134] Other parties submitted that the charge imbalances would net out or smooth out over time.[135] PwC submitted that "Cost-reflective pricing has little or no impact on sunk investments and price discovery is only important when a new investment is being considered".[136]

6.60 Transpower (CEG) submitted that a cross-subsidy does not exist or had not been established. Transpower (CEG) further noted that "From an economic perspective, in the presence of significant fixed, sunk costs, all that matters is whether prices are subsidy-free, ie between incremental costs and standalone costs. The short-run incremental cost of transmission is equal to the cost of losses and any constraints. These short-run costs are reflected in the differences in wholesale spot prices between nodes. In other words, all transmission grid users pay a price that is at least equal to the short-run incremental cost of supply. The remaining fixed costs of the existing transmission assets are recovered through a series of fixed charges. It is safe to presume that none of these fixed charges exceed the standalone cost of supplying transmission services to any particular customer. This is because if the transmission charge levied upon a particular customer did exceed that level then it would rationally disconnect from the grid – and stand alone, as it were. The existing TPM is consequently subsidy-free".[137]

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[132] NZAS (p.18).

[133] Buller (p.10).

[134] Auckland Chamber of Commerce (p.1).

[135] For example, Auckland Chamber of Commerce (p.1), Counties Power (p.11), PwC (p.5).

[136] PwC (p.5).

[137] Transpower (CEG) (p.22).

6.61 Transpower (CEG) further submitted that "the concern expressed in the Options Paper about the 'cost-reflectivity' of transmission costs appear not to be motivated solely by efficiency considerations. Rather, they seem to be based also on notions of equity… that is not to say that there is no merit in seeking to implement a more equitable allocation of charges… 'fairer' charges have the potential to be less contentious and more durable".[138]

6.62 EMA [Employers and Manufacturers Association] Northern submitted that "Taxpayers (who are also energy users in the north of Taupo region) have significantly subsidised the building of essential common infrastructure assets south of Taupo. This is especially the case with the road network where the extension of the road network…is the result of subsidies from the north of Taupo region".[139] The Authority notes that cross-subsidisation that has occurred in other sectors is not a matter that is relevant to the efficiency of the current TPM.

6.63 Some parties submitted that the current TPM provides efficient price signals.[140]

6.64 In particular, while Business NZ agreed that the current TPM's price signals were not sufficiently adaptive, it considered that Transpower's operational review showed that price signals can adapt, and adapt reasonably quickly.[141]

6.65 After consideration of submissions, the Authority's view is that the current TPM results in prices that are not service-based and cost-reflective, and so adapt poorly over time. The data provided above provides evidence that this has been the case in the recent past. The Authority believes this problem will increase over time, causing inefficient grid use and inefficient grid investment.

6.66 Regarding the submission by Transpower (CEG), the Authority notes that, while no customers have disconnected from the grid, there is a material risk that some large consumers may exit in the near term. While there are a number of factors that would influence this, including demand for their products, the exchange rate, and the cost of other inputs including electricity, the materiality of transmission charges mean transmission charges alone could cause inefficient exit. Moreover, it is commercially rational for a party considering exiting to defer making an exit decision if there is a material probability that the TPM review may reduce its charges. The fact that such an exit has not occurred is not therefore evidence that charges are less than standalone cost.

6.67 Further, the fact that some load and North Island generators pay no interconnection charges, and in the case of North Island generators, no HVDC charges, means there is a possibility that some of these customers are paying a charge that is below incremental cost. While these customers pay connection charges, the connection to the grid of at least some of these parties is likely to have involved additional costs not covered by the connection charge. If that is the case, their charges will be below incremental cost, implying a subsidy.

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138 Transpower (CEG) (p.27).

139 EMA Northern (p.2).

140 EMA Northern (p.2), Orion (p.2), Unison (p.8).

141 BusinessNZ (p.3), Transpower (CEG) (p.1, 18).

6.68 While South Island generators also pay no interconnection charge, they do pay HVDC charges. For this reason, their transmission charges are more likely to be above incremental cost than North Island generators, who only pay connection charges. The question then arises whether their charges are above standalone cost. Since they do not pay interconnection charges, this seems less likely.

6.69 The Authority also notes that distributors do not pay nodal prices so it is incorrect to say, as Transpower (CEG) did, that “all transmission grid users pay a price that is at least equal to the short-run incremental cost of supply”, as distributors do not pay such a price.

6.70 Regarding the submission by Business New Zealand, the Authority agrees that Transpower’s operational review demonstrated that price signals can adapt relatively quickly by changing the number of peaks relied on to determine the existing interconnection charges, or changing the use of peak injection to mean injection for HVDC charges. However, the Authority considers that the current TPM guidelines severely limit the extent to which Transpower could develop a TPM that is service-based and cost-reflective. In particular, the current guidelines require that:

(a) the interconnection charge is a postage stamp charge, so the rate of the charge must be constant across all regions, although the magnitude of the parameters used for calculation of the charge can vary between regions (eg RCPD was previously calculated according to 100 peaks for the LNI and LSI and 12 peaks for the UNI and USI)

(b) the costs of the HVDC link must be recovered only from South Island generators that inject into the grid, restricting the extent to which the HVDC charge can be adjusted to address inefficient signals from the charge.

6.71 After considering submissions, and taking into account Transpower’s operational review, the Authority remains of the view that the current TPM provides price signals for using the interconnected grid that are not service-based or cost-reflective, and so adapt poorly to changes in circumstances.

Poor price signals are incentivising inefficient participation in grid investment decision-making processes and so inefficient grid investment decisions occur

6.72 The above subsection shows that poor price signals are incentivising inefficient use of the interconnected grid, inefficient investment in the interconnected grid, and inefficient investment by grid users. In effect, these issues are “demand side” issues.

6.73 This subsection focuses on the supply side. It explains why and how poor price signals make it harder for the Commerce Commission to identify whether Transpower’s grid investment proposals are the most efficient option for meeting projected use of the interconnected grid.

6.74 The essence of the issue is that the spreading of the interconnection charge dilutes incentives for parties to reveal and promote the most efficient investment options, including alternatives to transmission, for meeting projected demand for transmission services. This undermines the discovery of efficient transmission investments and increases the chances of inefficient investment decisions for the interconnected grid.

6.75 While the grid investment approval regime has a mechanical element to it, so that investments are approved if they provide net electricity market benefits (in the case of most investments) or are the lowest cost solution to meet the deterministic limb of the grid reliability standards (in the case of investments in the core grid), the Commerce Commission gathers information from Transpower and parties who take the opportunity to make a submission, to inform its consideration of an investment.

6.76 As discussed above, under the current interconnection charge, the cost of each interconnection investment is spread across all load, while under the current HVDC charge the cost of each HVDC investment is spread across South Island generators. The result is that the customers facing the charges pay a lot for investments that other users benefit from, some users pay only a portion of the costs of investments for which they are the main beneficiaries, and some users pay virtually nothing for investments that benefit them substantially.

6.77 This allocation of costs creates poor incentives to identify the most efficient investment options for meeting projected use of the interconnected grid:

(a) it creates incentives for grid users to promote grid investments that benefit them even when the full economic costs exceed the economic benefits likely to be delivered, potentially encouraging more transmission capacity than is economic

(b) it creates incentives for grid users to promote interconnection investments that substitute for connection investment they would otherwise have to pay for, even when the former is less efficient than the latter

(c) it creates incentives for grid users to oppose grid investments that do not benefit them, even when those investments are justified.

6.78 In contrast, if transmission prices are service-based and cost-reflective, it would create incentives for grid users to promote a grid investment only if the benefits to them outweigh their share of the cost of that investment.

6.79 In addition, service-based and cost-reflective prices encourage users to take a close interest in investments that are expected to benefit them. In particular:

(a) if a grid user would be better off with the investment, it will have strong incentives to provide high quality information to support the investment

(b) if a grid user considers their benefits could be delivered with a lower cost investment, it would have strong incentives to provide evidence to support this to the Commission, as this would mean the grid user would face lower charges.

6.80 Service-based and cost-reflective pricing promotes greater scrutiny because the more a particular individual is affected by a decision, the greater the interest they will have in that decision, and the greater the incentive to engage in the decision-making process. The Authority notes that this often gives rise to very strong local opposition to large development projects, such as major roads and transmission and generation projects.

6.81 In contrast, the current system creates incentives for grid users not to submit on most investments in the interconnected grid, since even if they can affect the decision, the financial benefit that they gain from affecting it is limited. The Authority considers that this is likely to be part of the reason why, under the current TPM, there is limited engagement with the Commerce Commission's transmission investment approval process.

Consideration of submissions and the Authority's response

Importance of the TPM to efficient participation

6.82 A number of parties submitted that a change to transmission pricing is unlikely to incentivise participants to participate in investment decision-making (for example, because parties have limited resources, because of the complexity of investment proposals, or because of the small proportion that transmission costs represent of overall costs).[142]

6.83 The Authority considers that it is reasonable to expect that service-based and cost-reflective charges can support better participation in the investment approval regime under the Commerce Act, for the reasons noted above. In particular, the incentive on users to participate in transmission investment decision-making depends on how much their participation can affect the transmission charges they face. This incentive is much stronger with service-based and cost-reflective charges than with postage stamp charges.

6.84 The Authority considers that support for its view that the existing TPM does not support efficient investment has been provided through submissions and discussions with the Authority. In particular, Carter Holt Harvey submitted that there are investments that should not have been made or should have been deferred. Meridian and NZAS submitted that cost-reflective pricing would lead to more efficient participation.[143]

6.85 Levying charges over a broad base reduces the ability of users to influence the charges they face, and so lowers incentives to support or oppose investments. The Authority heard when it met with parties to discuss the options paper that this was a key reason why the interconnection charge is a postage stamp charge, as Transpower had previously had difficulty progressing investments because of opposition from those who would have had to pay for them. However, the Authority considers that this is a key weakness of the interconnection charge. Adopting service-based and cost-reflective charges would strengthen incentives to support or oppose investments, and therefore lead to better information being provided in relation to approval of investments.

6.86 Some submitters have argued that cost-reflectivity in investment is only relevant for new assets, and that the costs of existing assets should be recovered from all users in a way that minimises the overall distortion of collection.[144]

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[142] For example, Powerco (p.1-2, p.4) submission to the TPM options working paper.

[143] Orion (p.2-3), PwC (p.5), Transpower (CEG) (p.1,29), Unison (p.9), CHH (p.2), Meridian (p.9), and NZAS (p.23) submissions on the TPM options working paper.

[144] For example, Vector (p.2), and AECT (p.2) submissions on the TPM options working paper.

6.87 The Authority acknowledges that service-based and cost-reflective pricing is more important for new assets. However, for the reasons outlined in chapter 5, the Authority considers that it is important for existing assets as well as new ones. In particular, if users of new transmission investment suspected that, after an investment was constructed, their charges would no longer reflect the full cost of that investment, it would undermine the incentive for them to inform the Commerce Commission of their true investment preferences. The only time-consistent[145] way to ensure that true preferences are revealed is to ensure that the main users of the asset pay for it in a way that reflects the benefit they get from it.

Importance of the TPM to efficient investment decisions

6.88 The Authority recognises that many submitters remain sceptical of the relevance or importance of the TPM to efficient investment. For example, some parties submitted that it is not the Authority's role under the Code to consider efficient investment.[146] The Authority disagrees. All three limbs of the Authority's statutory objective require the Authority to consider efficient investment if it is to promote the long-term benefit of consumers. For example:

(a) in relation to efficient operation, if the Authority failed to consider efficient investment it would also fail to promote efficient operation because it would fail to consider how more efficient technologies support efficient operation

(b) in relation to competition, if the Authority did not consider efficient investment, it would fail to consider how new entry or substitution could help promote competition

(c) in relation to reliability, if the Authority did not consider efficient investment, it would fail to consider how technological development would help promote reliable supply.

6.89 Some parties submitted that the TPM had a much smaller potential impact on efficiency compared with the potential efficiency impacts of the Commerce Commission's Capex IM and associated processes.[147] However, the relevant question is whether a more efficient TPM would provide net benefits, which is addressed in this paper in the cost-benefit analysis of the Authority's proposal.

6.90 Related to this, some submitters argued that the Commerce Commission's regulatory regime provides sufficient checks on inefficient investment. While the Authority recognises that the Commerce Commission regime provides incentives on Transpower to postpone replacements and upgrades (subject to meeting

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145 Time consistency refers to the situation that arises when someone makes a commitment to take an action in the future. If the incentive to *keep* the commitment is the same as the incentive to *make* the commitment, then the example is time consistent. However, if the incentive to keep the commitment is significantly less than the incentive to make the commitment, then we say that the example is time-inconsistent or that there is a time-consistency problem. See for example: http://econlog.econlib.org/archives/2009/12/time_consistenc.html.

146 For example, submissions on the TPM problem definition working paper: ENA (p.12), Genesis (p.8), Mighty River Power (p.1,2-5,8,11), Orion (p.7), TrustPower (p.4), Vector (p.4).

147 For example, submissions on the TPM problem definition working paper: Carter Holt Harvey (p.4), Orion (p.11), Pioneer (p.2).

quality standards), the Authority does not consider that this regime in itself guarantees efficient investment for three principal reasons:

(a) Unless grid users face an efficient price signal they will not be efficiently incentivised to assist to discover the most efficient transmission investments or alternatives, as discussed above.

(b) While the Commerce Commission's regime incentivises Transpower to postpone investments when it is efficient to do so, Transpower has an incentive to maximise its approved operating and capital expenditure budgets, as it is permitted to keep a portion of the difference between approved budget and actual spend. As with all regulated businesses, there is a problem of information asymmetry as Transpower knows more about its business than any other party, including the Commerce Commission. The Authority therefore considers that it is likely to be beneficial to have additional checks and balances, including through transmission charges to help ensure that the level of investment approved is efficient. As is discussed above, efficient pricing incentivises grid users to ensure that the level of investment best meets their demand for transmission services, which will help promote efficient transmission investment.

(c) The implication from agency theory that the Commerce Commission will have less information about the need for an investment than Transpower, combined with asymmetric risk to the Commerce Commission from failure to approve an investment that is actually needed (ie, analogous to a type II error), and a similar risk to Transpower from failure to propose such an investment, implies a bias towards approval of unnecessary investment. The spreading of the interconnection charge weakens incentives on parties paying the charge to take steps to engage in the process to correct such potential bias.

6.91 Some parties submitted that deferring investment may not benefit consumers because, in terms of risks to consumers, it is better to build too big and too early than too small and too late.[148] The question, however, is whether the TPM promotes efficient transmission investment. Transmission investment involves significant economies of scale, so transmission investment is likely to require building to a scale in excess of demand in the short to medium term. However, this does not mean that the timing, scale or nature of transmission investment could not be made more efficient, while still meeting consumers' demand for reliability.

6.92 Mighty River Power submitted that, even if the TPM could affect investment outcomes, there is little prospect of material investments in the near future, and the Authority has not satisfactorily demonstrated that capex requirements can change very quickly.[149] The Authority considers that the recent announcements regarding closure of thermal plant are an example of how circumstances affecting transmission investment can change quickly. Another example is the potential

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[148] For example, submissions on the TPM problem definition working paper: ENA (p.8-9), Mighty River Power (p.7), Vector (p.4).

[149] MRP (p.5) submission onthe TPM options working paper.

exit of major transmission customers, such as NZAS. Transmission charges should be able to adapt to such changes, but the current TPM provides limited ability to do so. For example, if NZAS exited, this would increase transmission charges for all interconnection customers, despite the fact that their demand for transmission services had not changed. Further, the resulting increase in charges could potentially trigger the exit of other customers.

6.93 Some parties that commented on the problem definition in the options working paper submitted that the Authority has not established that past transmission investments have been inefficient. However, as noted above, Carter Holt Harvey submitted that there are investments that should not have been made or should have been deferred. Further, the fact that several submitters considered that the charges the Authority has been considering should be based on optimised costs[150] suggests at least some transmission investment exceeds what is necessary to meet foreseeable demand, implying it is inefficient.

The current TPM is not durable

6.94 The Authority is of the view that, because charges under the current TPM are not service-based or cost-reflective, the TPM is not durable. 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. Poor durability creates long-term uncertainties, potentially causing grid users to make inefficient location and investment decisions. It also results in resources being directed unnecessarily at lobbying for variations to the TPM.

6.95 The current TPM has been in place for almost 8 years. During that time, issues such as HVDC pricing have been extremely controversial and the fundamentals of the current TPM have been under review for most of its existence.

6.96 In the options working paper, the Authority stated that it was concerned with the divergence between costs and prices under postage stamp pricing. The Authority stated that, under the existing TPM, the problem was likely to continue to grow over time given the imbalance of economic and population growth between regions such as Auckland versus the rest of the country. The Authority considered that this would increase the likelihood of lobbying for fundamental change to the TPM, thereby creating further uncertainty, which would undermine efficient investment in and efficient operation of the transmission system and associated systems.

6.97 The Authority acknowledged in the options working paper that some durability issues may be dealt with through Transpower undertaking periodic operational reviews of the TPM (such as the 2014/15 TPM operational review). However, the Authority considered that TPM reviews under clause 12.85 of the Code were limited by the TPM guidelines. The Authority noted that this meant there may be situations where Transpower could not recommend optimal changes to the TPM

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[150] For example, IEGA (ASEC report) (p.14), Marlborough Lines (p.7), and MEUG (p.2) submissions on the TPM options working paper.

because they would not be consistent with the guidelines. The Authority considers that this could result in potential for inefficient delay in changes to the TPM. It could also create uncertainty for investors in long-life assets such as generation (including distributed generation), as investors will not know whether and how the TPM pricing signals will change.

Consideration of submissions and the Authority's response

6.98 Of the submissions on the options working paper that addressed durability, most of the comments focused on identifying durability problems with the Authority's options. Of the limited number of parties commenting on the durability problem definition, some parties submitted that the Authority has not established that the current TPM is not durable. For example, Unison submitted the issue of durability was open to interpretation and that the Authority's proposed options were likely to have durability problems. Transpower submitted that the ample scope to address issues through incremental reform suggests that the TPM is durable. Trustpower submitted that the difficulty in establishing a better option than the status quo indicates that the current TPM is durable.

6.99 The Authority recognises Unison's argument that durability is subjective and the Authority accepts that durability is difficult to quantify. However, the Authority continues to consider that postage stamp charging under the current interconnection charge will not be durable, as parties will continue to seek changes to the current TPM to avoid paying for assets from which they get no benefits. This problem will be more pronounced because growth, and therefore transmission investment, is likely to be concentrated in certain regions.

6.100 The Authority agrees with Transpower's (CEG) view that a disparity across customers in the relationship between benefits and charges may affect perceptions of fairness, which may undermine the regime's durability.[151] It is unlikely that users in regions that will not benefit from new transmission investment for the foreseeable future will willingly pay for new transmission investment that does not benefit them. This further reinforces the need to have prices that reflect the benefit that each customer derives from new investment.

6.101 The Authority recognises that Transpower's operational review has resulted in a more efficient pricing signal in relation to the interconnection and HVDC charges. While the Authority agrees that this should improve the TPM's durability, the Authority remains of the view that the current TPM guidelines restrict the extent to which Transpower can move towards a more efficient TPM.

Problems in relation to the connection charge

6.102 The current connection charge is a market-like charge and consequently service-based and cost-reflective. It is service-based because the costs of each connection service are charged to the party receiving the service. It is cost-reflective because the charge for providing connection services reflects the cost of providing the service.

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[151] Transpower (CEG) (p.27) submission to the TPM options working paper.

6.103 However, the Authority is also of the view that the TPM has the following problems in relation to the connection charge:

(a) it inefficiently incentivises parties to seek to have assets configured so that they are classified as interconnection assets

(b) it does not explicitly deal with the potential implications of the staged commissioning of transmission assets

(c) it allocates operating expenses within the connection pool using broad allocators for cost allocation rather than actual cost, which is likely to be inefficient.

6.104 The Authority is no longer of the view that the current average, or pooled depreciation based approach, to recovering the charges on connection assets is a problem.[152]

6.105 Each of these issues is discussed below.

Inefficient incentives to seek to have assets configured as interconnection assets

6.106 The Authority is of the view that the current TPM inefficiently incentivises parties to seek to have connection assets configured as interconnection assets.

6.107 The connection charge is highly targeted, being paid exclusively by those connected parties receiving the services delivered by the connection assets. In contrast, the costs of interconnection assets are spread across all load customers. This dichotomy in charging approaches across the asset classes means that parties that would otherwise pay for connection assets face significant financial incentives to configure those assets so that they are classified as interconnection assets. This may not be efficient.

6.108 In submissions on the connection charges working paper, Meridian agreed with the Authority that there was an incentive problem, while MEUG, Carter Holt Harvey and Orion submitted that asset boundaries could potentially be improved. MEUG submitted that it is a matter for a cost-benefit analysis to determine whether a change to the current connection charge is required.[153]

6.109 Some submitters that provided feedback on the connection charges working paper were of the view that the problem is resolvable through contractual means.[154] While the Authority accepts that this may be the case in some circumstances, a contractual outcome will not necessarily address the problem of shifting connection costs into the interconnection pool, because the definition of a connection asset is not determined by contract but through the Code. Hence the Code provides the incentive to seek to reclassify connection assets as interconnection assets.

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[152] As expressed in the connection charges working paper.

[153] Meridian (p.1). Orion (p.2), CHH (p.2), MEUG (p.2).

[154] ENA (para 15, Powerco (p.2), Vector (p.4).

6.110 Other parties submitted that the problem of inefficient shifting of connection costs to the interconnection pool is theoretical and is not evident in practice.[155] However, the Authority considers that an inefficient incentive is a sufficient problem in itself to warrant addressing the problem. This is because it will at the very least generate unproductive activity as affected parties seek a way to take advantage of the different charging approaches between connection and interconnection charges. This outcome is not consistent with the Authority's statutory objective.

6.111 The Authority understands that the Te Awamutu–Hangatiki link discussed in the October 2012 issues paper provides an actual example of this classification problem in practice. In particular, while this link is being constructed through a customer investment contract by Waipa Networks (Waipa), the potential effect of the link is that, under the current definitions in the Code, some connection assets connected to or at the Te Awamutu and Hangatiki substations would become interconnection assets.

6.112 The Authority understands that the reason for the Te Awamutu–Hangatiki link was to improve reliability for Waipa customers rather than to shift costs into the interconnection pool. However, if the connection of the link leads to reclassification of other assets currently paid for by Waipa through connection charges, this clearly improves the business case for the project for Waipa. It would be better if proponents of such projects clearly faced the full costs arising from the project rather than have some of the costs socialised. This is because it would ensure proponents considered the full costs in deciding whether there were net benefits from the project.

Inefficient incentives during staged commissioning

6.113 The staged commissioning of assets that were part of the North Auckland and Northland (NAaN) project highlighted that there could be more clarity about the approach to charging when projects are commissioned in stages. Initially, the project was commissioned in a manner that meant the relevant assets temporarily met the definition of connection assets and provided connection services. However, by the time the project was completed the assets were joined to form part of a loop, and so were interconnection assets.

6.114 Transpower applied for an exemption, seeking to have the NAaN costs recovered through the interconnection charge, even though, for a period, the assets met the connection asset definition and provided connection services to Vector alone.[156] The Authority, however, declined to grant an exemption and decided that, for the initial period when the assets met the connection definition, it was more consistent with the Authority's statutory objective for the assets to be charged to Vector through the connection charge. In a subsequent High Court case about the interpretation of the definition of "connection assets", the High Court found that the Authority's interpretation of the definition of connection assets was

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155 Submissions on connection charges working paper: CHH (p.2), Counties Power (para 2.1), ENA (paras 12-15), Fonterra (para 10), Genesis (page 2), Powerco (p.1), PwC (para 8), Trustpower (para 3.1.2), Unison (p.1), Vector (p.4).

156 Refer to the Authority's website: http://www.ea.govt.nz/development/work-programme/transmission-distribution/exemption-application-classification-of-naan-assets-under-the-tpm/.

correct. Vector also subsequently applied for an exemption relating to the same issue. The Authority also declined to grant the requested exemption.

6.115 The Authority has taken into account feedback received on the potential problem of inefficient incentives during the staged commissioning of transmission assets.

6.116 Some parties submitted that it is efficient to commission assets when they are ready rather than defer commissioning until all the assets in an investment are built.[157] The Authority agrees that this may be efficient but the issue is not whether assets should be commissioned in this way but how the assets should be charged for. If the assets are providing connection services to a party, it is efficient that they are charged to that party for the period they are receiving the services. In that way the party can consider whether early commissioning would best meet their needs, while not raising charges to other parties not receiving the services. In turn, this will assist in ensuring that there are net benefits from the project.

6.117 Some parties submitted that the problem would rarely occur.[158] This may be the case but ensuring that the TPM can clearly deal with such situations is nevertheless likely to reduce transactions costs, reduce uncertainty and promote efficient investment.

Cost-reflectivity problem in allocation of operating and maintenance expenses in the connection pool

6.118 The Authority considers that the current method of allocating costs for operating and maintenance expenses for connection assets using broad allocators may not be efficient. This is because the broad allocators do not adequately reflect the costs of operating and maintaining different connection assets. To the extent that the costs are spread across all connection customers, this reduces the incentives for customers to scrutinise charges, which would otherwise place more pressure on Transpower to ensure that operating and maintenance costs are efficient.

6.119 The Authority considers that, ideally, connection charges allocated to connection customers at a connection location would be Transpower's actual costs in relation to providing, maintaining, and operating the connection assets at that location. If operating and maintenance costs were apportioned separately to individual assets, this would encourage both Transpower and the connecting party to take account of the likely impact of their actions on these costs.

6.120 However, the Authority considers that, where costs are common across multiple assets, the accurate allocation of operating and maintenance expenses to individual assets may be difficult to achieve and the increase in administration costs could make this inefficient.

6.121 In determining its position on the allocation of operating and maintenance costs, the Authority has taken into account submissions on the issue. Submissions on

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[157] ENA (para 18), Powerco (p.2), and Vector (p.5) submissions on the connection charges working paper.

[158] ENA (para 17), PwC for 21 distributors (p.3), and Vector (p.5) submissions on the connection charges working paper.

the connection charges working paper in relation to the allocation of operating and maintenance costs include those by the following parties:

(a) Meridian supported charging operating and maintenance costs based on actual costs rather than cost allocators.

(b) CHH submitted that there may be some cost efficiencies in improving incentives on Transpower to allocate costs realistically.

(c) Unison submitted that the current approach of averaging operating costs may be simpler but Transpower may be able to undertake a more detailed allocation of operating costs. The Authority agrees. A more detailed allocation would ensure charges for operation and maintenance better reflected underlying costs, but this is not to say that some use of allocators would not continue to be efficient.

(d) Unison further submitted that there would likely be compliance costs associated with changing the method by which operating costs are calculated, which would need to be passed through to the consumer.[159] The Authority recognises that more detailed allocation of costs may involve greater transactions costs, but the key question is whether there would be net benefits from the change, which would be assessed in cost-benefit analysis.

(e) Counties Power submitted that there would be difficulties in attributing connection maintenance costs to specific assets and that the Authority's proposal will not result in efficiency gains. The Authority notes that this submission is in contrast to the submissions from Meridian and CHH, and the submission from Unison suggests better attribution of maintenance costs may be possible.

(f) Counties Power also submitted that the proposal to attribute connection maintenance costs to specific assets would only be efficient if the change occurred in conjunction with depreciated replacement cost based (DRC-based) connection charges. Otherwise, customers would pay higher maintenance costs for an older asset, without the lower corresponding connection charges.[160] The Authority does not agree, because each customer will have the incentive to seek efficient connection assets and efficient maintenance if they face the full lifetime cost associated with the investment over its life.

(g) ENA submitted that there would be no marked efficiency benefit in changing the way operational and maintenance costs are allocated, as Transpower's customers do not have the ability to monitor or scrutinise Transpower's maintenance practices.[161] The Authority disagrees. More targeted allocation of operating and maintenance costs is likely to encourage Transpower to make its operating and maintenance practices more

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[159] Meridian (p.2), CHH (p.3), Unison (p.3-4).

[160] Counties (para 4).

[161] ENA (para 27).

transparent, which would assist in the monitoring and scrutiny of Transpower's operating and maintenance activity.

Charging based on pooled depreciation is not a problem

6.122 The current connection charge is based on the average historical cost (AHC) of the pool of connection assets.[162] In the connection charges working paper, the Authority proposed that there would likely be a net benefit from removing the averaging approach and basing charges on the actual book value of the set of connection assets used to provide connection services to a customer.

6.123 The Authority is now of the view that, while there may be problems with an averaging, pooled approach, the departure from this approach for connection assets would not be justified because it is unlikely to produce net benefits. As a result, the Authority has not included pooled depreciation as part of its problem definition.

6.124 In coming to its view the Authority has taken into account submitter feedback, including submissions that:

(a) there is no material problem with status quo connection charges.[163] While the Authority considers that this may be the case with some aspects of the connection charge, including in relation to pooling of depreciation, the Authority considers there are several problems with the connection charge, as noted elsewhere in this section

(b) there is no evidence that customers have incentives to seek more frequent upgrades or early replacement of assets under the current regime[164]

(c) there is no material cross-subsidy between connection pool charges for distribution customers, as most distributors are served by a mix of older and newer assets. If it is an issue, it would only be an issue for direct connection customers[165]

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162 Transpower describes the value of its assets in its RAB, including those that are connection assets, as based on average replacement cost. This was the description used by the Authority in the connection charges working paper. However, the Authority now understands that Transpower's total RAB, and the individual HVDC and interconnection assets in the RAB, are valued at depreciated historical cost (DHC). The Authority understands that a one-off adjustment was made to asset values in the RAB when Transpower's methodology changed from that of optimised deprival value to an historical cost-based methodology in 2006/2007 and so older assets may have been included in the new RAB at values other than DHC. The connection pool that sits within the RAB and contains connection assets is valued, in aggregate, according to DHC. However, within the connection pool, charges for individual connection assets are allocated according to replacement cost – the replacement cost of the connection asset divided by the replacement cost of the entire connection pool. Since replacement cost does not include an adjustment for depreciation while DHC which sets the size of the connection pool does, Transpower would over-recover the cost of connection assets if it did not discount connection charges to reflect the aggregate DHC value. The value of each asset in the connection pool is thus discounted by the same portion so that Transpower does not over-recover. Effectively all assets in the connection pool are depreciated to reflect the average age of the pool, ie, they are all assumed to be aged by the same percentage for the purposes of calculating charges. This is what was referred to in the connection charge working paper as average replacement cost..

163 Contact (p.1), Counties Power (p.5), ENA (para 12), Fonterra (para 10), MRP (p.1), Orion (para 4), Pioneer (p.1), Transpower (p.1,9), Vector (p.3).

164 MRP (p.3), Orion (para 16), Transpower (para 3), Trustpower (para 4.1).

165 Powerco (p.3).

(d) cross-subsidisation is not a great concern over the lifetime of a connection asset because it is likely that customers are paying the full cost of the asset over its life[166]

(e) the current TPM and Commerce Act regimes provide sufficient checks and balances to manage inefficient investment in connection assets[167]

(f) charges to the consumer should be related primarily to the services the asset provides, not age, and asset service levels did not vary considerably over the life of an asset[168]

(g) under an actual (non-pooled) DHC-based charging proposal, prices would be high when an asset is new and low when it is old. Vector noted that, as utilisation of assets often increases over time, this may not be efficient[169]

(h) an actual DHC-based charging would lead to unnecessary and/or undesirable volatility or price shocks.[170]

Problems with the prudent discount policy

6.125 As described in chapter 5, it is efficient for a grid user to connect to the grid provided they bear transmission charges at least equal to the incremental cost of supplying them with transmission services. The intention of the current prudent discount policy is to reduce incentives for inefficient bypass of the grid by providing a charge that:

(a) is at least the incremental cost of providing transmission services to the customer

(b) better reflects the extent to which a customer's demand for transmission services is sensitive to transmission charges.

6.126 As set out in the October 2012 issues paper, the Authority is of the view that the current prudent discount policy (PDP) may have the following problems:

(a) it does not apply when the alternative to connecting to Transpower's grid is investing in generation, which means that the PDP may not remove the incentive for inefficient disconnection under some circumstances

(b) it limits prudent discount agreements to a maximum of 15 years, which may be too short a duration to limit incentives for inefficient disconnection of load.

6.127 The Authority has considered further the circumstances in which the PDP should apply. As well as the circumstances outlined in paragraph 6.126 above, the PDP does not apply where there is a material risk that a transmission load customer (or downstream load customer) would inefficiently exit due to the transmission charge they would pay. In particular, the PDP requires identification of an

166 Unison (p.2).

167 Counties Power (p.2), Genesis (p.1-2).

168 CHH (p.2), ENA (paras 21-22), MRP (p.2), Orion (para 13), Powerco (p.2), PwC for 21 distributors (paras 19-21), Transpower (p.7), Trustpower (para 2.1.2), Unison (p.2), Vector (p.2-3).

169 Vector (p.3).

170 Genesis (p.4), MRP (p.3), PwC (para 13), Transpower (p.7), Vector (p.2).

alternative project that would enable bypass of the grid. This prevents application of a prudent discount if the customer is not able to identify an alternative project even if this meant it would exit the grid but would be willing to pay a charge at least equal to incremental cost. Such exit would be inefficient and result in higher charges on other transmission customers. The Authority therefore considers the PDP should apply in this circumstance as well as in the circumstances outlined in paragraph 6.126.

Loss and constraint excess—its ability to fund the costs of transmission services and problems with its current allocation

6.128 Use of the transmission system is currently rationed on a five-minute basis by the operation of the nodal spot electricity market. The scheduling, pricing and dispatch (SPD) model is used to dispatch generation resources for five-minute periods based on the half-hourly offer prices submitted by generators.

6.129 The SPD model dispatches generation by taking into account security constraints in the grid and estimated energy losses from transmitting electricity from grid injection points to grid exit points. The presence of losses and constraints results in price differences across the grid, and produces a surplus (referred to as loss and constraint excess (**LCE**[171]) that is the difference between what the clearing manager receives from the sale of electricity and what it pays to generators for electricity it purchases. The Code requires that LCE remaining following the settlement of FTRs be paid to “each grid owner”, which includes Transpower.[172] The requirement for LCE to be credited to transmission customers is made under clause 45.1 of the Benchmark Agreement. This clause says that the distribution of LCE to customers must be according to Transpower’s “prevailing methodology”.[173]

6.130 Under its current LCE allocation methodology, Transpower pays LCE to its transmission customers in proportion to their transmission charges. Under this methodology, the amount each customer receives depends on the LCE arising in relation to the particular class of assets they pay for, ie connection, interconnection, and HVDC, and the revenue remaining after settlement of FTRs. The payment of LCE has the effect of reducing the customers' transmission charges.

6.131 Because LCE is generated by the efficient operation of the spot electricity market, its collection does not involve any loss of efficiency (aside from transactions costs).[174] It is in effect a rental that accrues to the owner of the transmission asset. It is therefore a logical source of revenue to fund transmission services. In practice, however, a large funding deficit (or residual)

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[171] The loss and constraint excess is also referred to as loss and constraint rentals and “transmission rentals”.

[172] Clauses 14.6(6), (7).

[173] Clause 45.1(a) of the Benchmark Agreement.

[174] There is one further potential inefficiency where the user has the option of owning the transmission asset. In that case, because the transmission customer can access the LCE by owning the asset, it creates an incentive for them to own the asset in some circumstances when that would increase overall system costs. This inefficiency is most likely to be relevant for policy with respect to connection assets.

occurs because grid investments typically exhibit large economies of scale, which results in significant spare capacity.

6.132 The fact that the Code is not specific about how Transpower should allocate the LCE it receives creates some uncertainty for customers because there is nothing to stop Transpower altering the way it allocates LCE in future. Further, the allocation of LCE has the potential to undermine price signals intended to be provided through both nodal pricing and the TPM.

6.133 To reduce this uncertainty, and ensure that the allocation of LCE does not undermine efficient price signals, it is proposed to specify the allocation method in the Code.

Problems with the recovery of the cost of network reactive support assets

Problems with static reactive support

6.134 The need for static reactive support equipment arises because transmission customers and their downstream customers are using power in a manner that results in a poor power factor[175] for other transmission users. However, as stated previously, revenue for static reactive support[176] assets is currently recovered in the same way as other interconnection assets: through the interconnection charge spread among all customers.

6.135 This means that the parties that cause the need for static reactive investments through their acts or omissions—use of equipment with a poor power factor and/or failure to invest in static reactive support equipment themselves to offset a poor power factor—are only bearing a small portion of the full costs of those acts or omissions. This creates an inefficient incentive for the causers of the need for static reactive support to undertake too much activity (or too little) relative to the situation where the causers pay the full cost of their acts or omissions. Economically, this situation is termed a negative externality.

6.136 It is possible to clearly identify the parties whose activity leads to the need for static reactive grid investments, but who are not, even though they are exacerbators, charged directly for the cost of that investment.

6.137 In addition, there are problems with the power factor management arrangements under the Code:[177]

(a) Off-take customers cannot practically comply with the current Connection Code unity power factor requirement in the UNI and USI regions at a reasonable cost.

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[175] Reactive power (supporting voltage levels) in relation to active power (providing useful power to a load) is measured by 'power factor' (pf). Unity power factor (pf = 1.0) indicates no reactive power flow as a proportion of active power flow into a load (ie, all power flowing is active power). Increasingly 'lagging' power factor (ie, pf = 0.99, 0.98, 0.97 and so on) indicates increasing amounts of reactive power flow into a load as a portion of active power.

[176] Static reactive support is equipment, such as capacitor banks, to address power quality problems caused by equipment with a poor power factor.

[177] TPAG report, section 7.

(b) Transpower cannot practically enforce breaches by off-take customers of the power factor requirements in the Connection Code.

(c) The current practice of minimising Transpower's expenditure on static reactive support—by requiring off-take customers to invest (and by incentivising their customers to invest) in their own reactive power compensation measures so that Transpower's investment is not required—is inconsistent with promoting the efficient level of investment by Transpower in such equipment (which is non-zero).

6.138 As a result, the Authority has proposed the introduction of a kvar charge so those that cause the need for reactive support pay for it, and to amend the power factor requirement in the Connection Code to 0.95 so that it can be practically achieved.

6.139 A number of submissions on the October 2012 issues paper broadly supported the development of a kvar charge. The Authority infers from those submissions that those submitters agreed there was a problem that needed to be addressed.[178]

6.140 In July 2013, the Authority announced that it was considering progressing a new charge for static reactive support as a standalone change to the TPM. However, the Authority decided not to pursue the change because upward trending power factors suggested that management of reactive power had improved and this reduced the net benefit of bringing forward work on the static reactive support charge. The Authority announced that it still intended to advance changes to static reactive support as part of the overall TPM change package.

6.141 Analysis of power factors by the Authority in August 2015 suggests that power factors are continuing to improve (see Figure 11 below), implying there would be little immediate benefit from a kvar charge at this time. However, the Authority recognises that this situation could change in the future.

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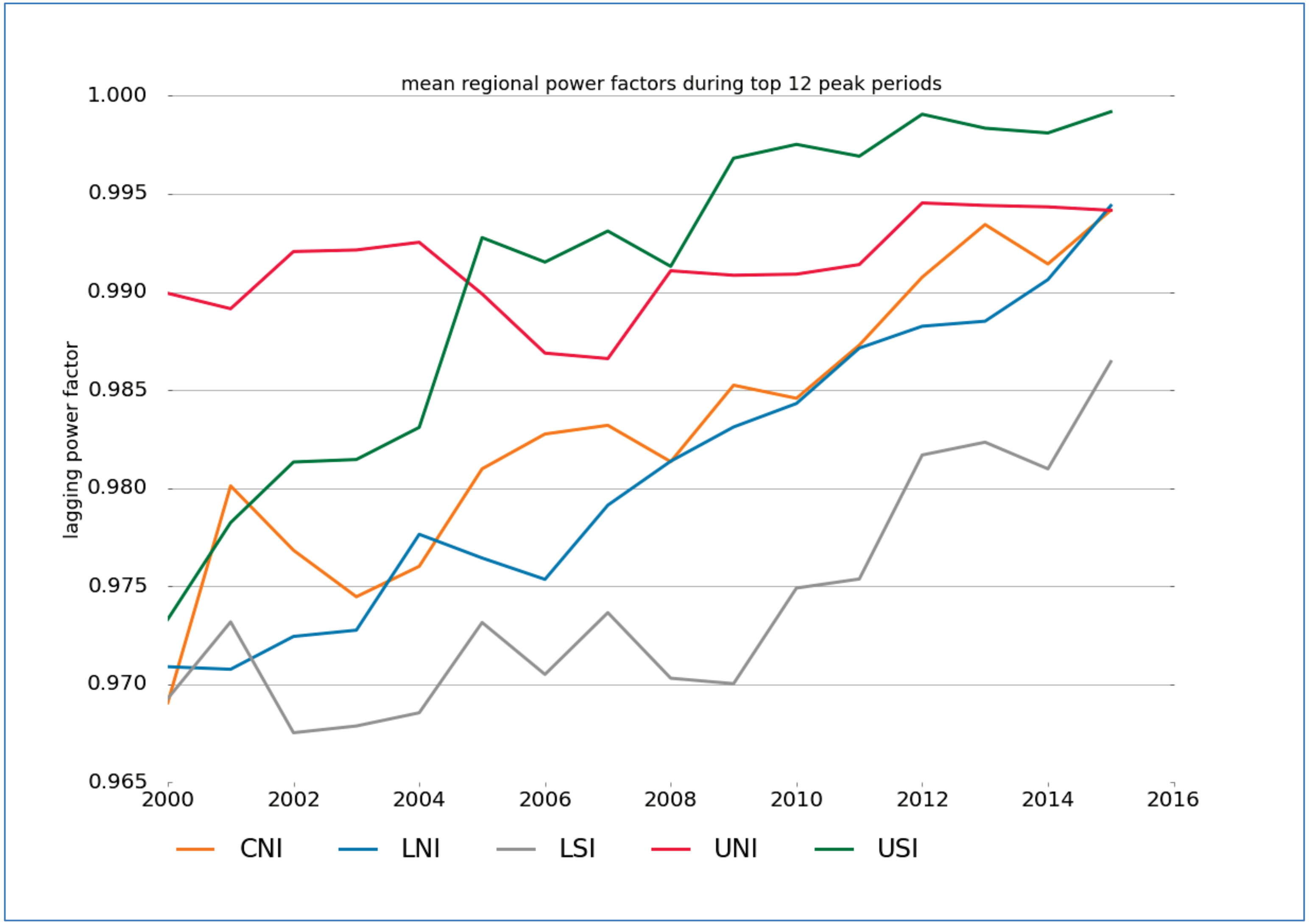
[178] For example, Trustpower, Nova, Meridian, Mighty River Power, and Contact supported or partially supported the proposed kvar charge in their submissions on the October 2012 issues paper.

Figure 11: Mean regional power factors during top 12 peak periods



6.142 Of the submissions on the options working paper, six parties submitted on the kvar charge. One party that supported the kvar charge did so on the basis that it would incentivise parties to manage their own reactive support requirements.[179] Two parties submitted that the charge should reflect local conditions and not be spread on a regional basis.[180] One party submitted that it did not object to the charge, although it recognised that the charge would collect only minimal revenue.[181]

Problems with dynamic reactive support

6.143 As is the case for static reactive support equipment, dynamic reactive support is provided to address an externality—management of voltage instability caused by some specific parties. Under the current TPM, the costs of dynamic reactive support assets provided by Transpower are recovered through the interconnection charge, which is a postage stamp charge spread across all load customers.

6.144 Therefore, the use of the postage stamp interconnection charge to recover the costs of dynamic reactive support creates similar inefficient incentives and outcomes to that described for recovering the costs of assets to provide static reactive support.

6.145 Dynamic reactive support reduces transmission losses, which enables greater power transfer into a region. Accordingly, it may be efficient to charge the parties benefiting from the greater power transfer enabled by dynamic reactive support to ensure they have incentives to take into account the costs of dynamic reactive support in their investment decisions.

Now is a good time to address these problems

6.146 As outlined above, the fact that key elements of the current TPM are not service-based or cost-reflective incentivises inefficient grid use and inefficient investment in transmission and other electricity assets. This effect is ongoing, and is self-perpetuating. Consequently, the longer inefficient transmission prices remain in place, the worse the overall inefficiencies that result to the electricity system will become.

6.147 This suggests that the earlier these problems can be fixed the better. This is so despite the fact that parties who have invested on the back of inefficient price signals and parties who would face a rise in charges following a change to a more efficient TPM will likely strongly oppose such a change. The Authority recognises that changes in transmission prices will be seen by some parties as evidence of an unstable and uncertain regulatory regime.

6.148 The Authority believes that the Authority consistently and transparently pursuing its statutory objective is the best way for it to promote regulatory certainty and the

179 The Lines Company (p.7).

180 Fonterra (p.4), Meridian (p.18).

181 NZAS (p.32).

right climate for investment in the capital intensive electricity industry over the long-term.

6.149 The current low to moderate grid investment outlook is not a good reason for refraining from reforming the TPM at this time. The grid investment outlook is inherently uncertain and can change very quickly. As an example, the recent thermal closures in the vicinity of Auckland may create the need for further grid investment. Another example would be the need for grid investment if the aluminium smelter at Tiwai closed. Then it is likely there would be a need for significant grid investment to transport electricity north from the lower South Island region, and also the need for additional grid investment into Auckland if closure of the smelter led to the closure of the last two coal-fired units at Huntly. Accordingly, there is a sound basis for adopting a more efficient TPM now, as that would mean there is an efficient TPM in place to cater for the eventuality that the grid investment programme is expanded.

7 Proposed guidelines for Transpower to follow in developing a TPM

Introduction

7.1 Appendix A sets out the Authority's proposed guidelines for Transpower to follow in developing a TPM (proposed guidelines). The proposed guidelines consist of general guidance to Transpower regarding the development of the TPM, four main components, and five additional components.

7.2 This chapter describes the components of the proposed guidelines and the Authority's reasons for including each component.

7.3 In addition, this chapter discusses proposed amendments to provisions in the Code[182] that are relevant to the TPM and the Authority's reasons for proposing those amendments.

General guidance

7.4 The proposed guidelines include general guidance to Transpower on the matters to which the TPM must be directed.

Main components

7.5 There are four main components in the proposed guidelines:

(a) a connection charge

(b) an area-of-benefit (AoB) charge

(c) a residual charge

(d) a prudent discount policy.

Additional components

7.6 Under the proposed guidelines, Transpower would also be required to consider whether to propose any of the following "additional components" for the TPM:

(a) a method for determining how assets are classified during staged commissioning

(b) a method for charging for transmission assets that were originally classified as connection assets but subsequently become non-connection assets due to other investments

(c) a method for calculating and allocating operational and maintenance costs on an actual cost basis, for assets in relation to which the connection charge or area-of-benefit charge applies

(d) an LRMC charge

[182] Including documents incorporated by reference. Consultation on these proposed Code amendments will be in accordance with the Authority's Consultation Charter and Code Amendment Principles, and will be undertaken at a later date, likely at the same time as consultation occurs in relation to Transpower's proposed TPM (in the event that new guidelines are published).

(e) a kvar charge.

7.7 The proposed guidelines would require Transpower to propose an additional component if doing so would be practicable and consistent with the matters in clause 12.89 of the Code.[183]

7.8 The proposed guidelines would also specify that it would be desirable for Transpower to keep under review any of the additional components not initially incorporated into the TPM. In relation to those components, Transpower has the option to propose a variation under clause 12.85 of the Code after the initial development and approval of a new TPM.[184]

Other changes relevant to the TPM

7.9 The Authority also proposes to make the following changes relevant to the TPM:

(a) amending Part 12 of the Code to specify a methodology that Transpower must use to allocate LCE

(b) amending the "unity" minimum power factor specified in the Connection Code (a document incorporated by reference into the Code).

General guidance to Transpower

7.10 The proposed guidelines contain general guidance to Transpower regarding the matters to which the TPM must be directed.

7.11 The proposed guidelines provide that, to be consistent with the Authority's statutory objective specified in section 15 of the Electricity Industry Act, as required by clause 12.89 of the Code, the TPM must be directed at:

(a) facilitating efficient investment in the electricity industry by providing incentives for the right investments to occur at the right time and in the right place. Those investments may be in the transmission grid, generation (including distributed generation), distribution networks or the demand-side

(b) facilitating the efficient operation of the transmission grid, generation (including distributed generation), distribution networks and demand-side management. This means providing incentives so that the day-to-day operation of transmission, generation, distribution, and demand-side management involves an efficient trade-off between reliability and cost.

7.12 The general guidance reflects the Authority's interpretation of its statutory objective with respect to transmission pricing, as set out in the Authority's DME framework.

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[183] Clause 12.89 of the Code states: (1) Transpower must develop its proposed transmission pricing methodology consistent with –

(a) any determination under Part 4 of the Commerce Act 1986; and

(b) the Authority's objective in section 15 of the Act; and

(c) any guidelines published under clause 12.83(b).

(2) Transpower's proposed transmission pricing methodology must include indicative prices to allow the Authority and interested parties to understand the impact of the methodology on designated transmission customers.

[184] Clause 12.85 provides that Transpower would only be able to submit a variation if at least 12 months had passed since the last approval of the TPM.

Main component 1: connection charge

Proposal

7.13 Subject to the possible inclusion of additional components 1 to 3, the proposed guidelines would require that the TPM:

(a) include a definition of connection asset that corresponds to the definition of that term in the current TPM

(b) charge for connection assets on the same basis, and with the same effect, as the current TPM.[185]

7.14 That is, the current method for charging for connection assets would be retained.

Discussion

7.15 The current connection charge is a market-like charge, as described in the Authority's DME framework, and is largely consistent with the service-based and cost-reflectivity principles discussed in chapter 5.

7.16 Many submitters were of the view that the current connection charge is efficient, and that a change from the status quo would not result in improvements in efficiency.[186]

7.17 The Authority believes that calculating and allocating operational and maintenance costs on an actual cost basis would make the charge more cost-reflective, potentially improving the efficiency of the charge. However, it may not be practicable to address this issue immediately because Transpower may not have sufficient resources to undertake such a change in parallel with the main components of the Authority's proposal. Hence, the issue of operational and maintenance costs is covered later in this chapter, in the section titled Additional component 3.

The cost basis for the connection charge

7.18 The current connection charge is a pool-based approach, calculated on the regulatory asset value of connection assets, so the full capital-related costs of connection assets are recovered from the group of transmission customers required to pay a connection charge.

7.19 The total quantum of the asset charge is calculated based on the original cost of building all of the assets in Transpower's RAB less depreciation,[187] while the allocation between assets is based on replacement cost (**RC**), the forward-looking cost of replacing each asset (but using a special definition of replacement cost for certain assets, as explained in Chapter 2). Since the asset component allocator (the RC allocator) is not adjusted for depreciation for a particular asset, in effect the average level of depreciation of the pool of assets is applied to each

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185 Throughout this chapter, references to the 'status quo' or the 'current TPM' should be read as the TPM as amended by the recent Transpower TPM operational review.

186 For example, in submissions on the connection charges working paper: Contact (p.1), Counties Power (p.4), ENA (p.6), Fonterra (p.3), MRP (p.1), Orion (p.1), Pioneer (p.1), Transpower (p.1,9), Vector (p.3).

187 This corresponds with the term RAV_{conn} in clause 11 of the TPM.

asset. This is known as the average historical cost (**AHC**) of the relevant assets.[188]

7.20 The connection charges working paper characterised the asset component as being calculated on the basis of applying average depreciation to all connection pool assets, and described that as "ARC" or average replacement cost.

7.21 Since the Authority was considering removing the approach under the current connection charge of averaging depreciation across the pool of assets, the resulting cost basis for determining connection charges would have been depreciated historical cost (**DHC**), not depreciated replacement cost (**DRC**) as it was described in the connection charges working paper.

7.22 However, as noted above, the correct characterisation of the current connection charge is that it is based on AHC. Regardless of the characterisation of the basis of the current connection charge, the Authority now agrees with some submitters that the advantages of the current method of determining connection charges on the basis of average depreciation outweigh its disadvantages. The Authority's preferred approach for determining connection charges is accordingly AHC.

7.23 As some submitters noted,[189] charging based on average depreciation is more consistent with what occurs in workably competitive markets for utility-type services. For these types of services, aesthetics are largely irrelevant to the benefits customers receive from the service and therefore charges do not reflect the age of the asset providing the service. For example, airline fares are set irrespective of the age of the relevant aircraft.

7.24 In addition, if retail customers face variable charges, DHC-based charging creates incentives for customers to avoid using an asset when it is new (because the price will be high), and use the asset more when it is old and possibly congested (because the price will be low). However, if distribution pricing evolves in the way anticipated by the Authority, this problem should not arise, as retail customers would face either capacity-based charges (when future investment is not required), or peak demand charges (when demand would bring forward investment).

7.25 Under AHC-based charging, transmission customers may have lower incentives to scrutinise the efficiency of investments. However, this would only be the case if customers failed to consider the cost of the investment in net present value terms.

7.26 A disadvantage of AHC-based charging occurs when a customer is considering disconnecting from the grid. Customers would have lower incentives to seek to avoid replacements or upgrades, because the amount they would pay immediately following the investment would be lower under AHC-based charging

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[188] The connection charges working paper refers to RC as Average Replacement Cost or ARC. This is because Transpower's maximum allowable revenue (MAR) is based on DHC and is fixed. Moving to RC for the purposes of pricing requires that the value of each asset is reduced to reflect the average life of all assets in the connection pool.

[189] For example, see the following submissions on the TPM options working paper: Westpower (p.2), Top Energy (p.10), PwC (p.9).

than under DHC-based charging.[190] This means there is a higher risk of the replacements or upgrades of connection assets occurring and then being stranded soon afterwards. However, the Authority considers this problem may not be material, as Transpower can sometimes re-deploy stranded assets in other areas of its network, eg, transformers. The Authority welcomes submitter views on this matter.

Conclusion regarding connection charge

7.27 For the reasons described above, the Authority is of the view that a connection charge levied on the same basis as the current TPM (and with the same effect), subject to the possible inclusion of additional components 1 to 3, would best promote the Authority's statutory objective. In particular, the connection charge would promote efficient investment by providing parties with reasonably efficient incentives to take connection costs into account in their own investment activity, and to seek the connection option, and alternatives to it, that most cost-effectively meets their needs.

Main component 2: Area-of-benefit charge

Introduction

7.28 The proposed guidelines would require that the TPM include an area-of-benefit charge to recover the costs of interconnected grid assets.

7.29 The area-of-benefit charge would recover the costs of each "eligible investment" from generation and load customers located in the areas identified as benefiting from the investment. The intention is to levy the area-of-benefit charge across payers in proportion to their share of the benefits from each eligible investment. 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.

7.30 The Authority is proposing an area-of-benefit charge because it allocates the cost of upgrades to the interconnected grid in a way that is service-based and cost-reflective. It therefore provides grid users with better incentives than 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.

Proposal

7.31 The guidelines would require that the TPM include an area-of-benefit charge, with the features listed below. The Authority's reasons for each aspect of the proposal are discussed in more detail from paragraph 7.55 onwards.

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[190] The exception is if the disconnection occurred after the costs of the asset were fully recovered.

Single main service-based charge

7.32 The area-of-benefit charge would be a single main service-based charge for the interconnected grid.

Charge would apply to eligible investments

7.33 The area-of-benefit charge would recover the full cost of each asset (other than a connection asset) in an "eligible investment". Eligible investments would be any of the following:

(a) a project or programme of base capex or major capex that is commissioned on or after the date of the guidelines

(b) the following investments:

- (i) the North Island Grid Upgrade (NIGU) Project
- (ii) the Upper South Island Dynamic Reactive Support Project
- (iii) the Otahuhu Substation Diversity Project
- (iv) the HVDC (Pole 3) Project
- (v) the Wairakei Ring Project
- (vi) the North Auckland and Northland (NAaN) Project
- (vii) the Upper North Island Dynamic Reactive Support Project
- (viii) the Lower South Island Renewables Project
- (ix) the Lower South Island Reliability Project
- (x) The Bunnythorpe-Haywards Reconductoring Project

(c) Pole 2 of the HVDC link

(d) to the extent not covered by paragraphs (a) to (c), the costs of any payments by Transpower in respect of a non-transmission solution (as that term is defined in the Capex IM).

TPM would include a standard method and a simplified method

7.34 The proposed guidelines would require that the TPM include:

(a) a standard method to apply to each eligible investment valued at $5 million or more at the time the investment is commissioned, or at the completion date, as the case may be (“high value investments”)

(b) a simplified method to apply to any eligible investment valued at less than $5 million at the time it is commissioned, or at the completion date (“low value investments”).

Features common to the standard method and the simplified method

7.35 Transpower would develop these methods and processes in its development of the TPM. Both methods would be required in the guidelines to:

(a) identify the areas-of-benefit (for the standard method) or the main areas-of-benefit (in the case of the simplified method). 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

(b) apportion charges to each area-of-benefit based on the aggregate expected positive net benefit to the designated transmission customers to which positive net benefits are expected to accrue in that area-of-benefit

(c) allocate the charges to generation designated transmission customers and load designated transmission customers in an area-of-benefit so that each group is allocated charges that correspond to the proportion of the aggregate positive net benefits that the group is expected to receive from the eligible investment

(d) apportion the area-of-benefit charge between eligible investments, if a project or programme provides for replacement or refurbishment of assets contained in 2 or more of those eligible investments.

7.36 For eligible investments commissioned before 1 April 2019, expected benefits would be assessed as at 1 April 2019, for the expected remaining life of the investment. For all other eligible investments, expected benefits would be assessed at the date of commissioning or the completion date (as the case may be), for the remaining life of the investment.

Features specific to the standard method

7.37 The standard method would be required to:

(a) to the extent practicable, provide for charges to be allocated to designated transmission customers in an area-of-benefit so that each customer is allocated the proportion of the charges that corresponds to the proportion to the aggregate positive net benefits that it is expected to receive from the eligible investment in that area-of-benefit

(b) to the extent that it is not practicable for charges to be allocated in accordance with (a)

(i) allocate charges to load designated transmission customers in proportion to the physical capacity of each load designated transmission customer. The method for determining physical capacity would be the same as the method used to determine physical capacity for the purposes of the residual charge discussed later in this paper

(ii) allocate charges to generation designated transmission customers on the basis of each customer's average injection

(c) to the extent practicable, limit the need for Transpower to exercise discretion

(d) result in charges that are consistent with the identification of benefits (if any) in relation to the relevant investment proposal

(e) be consistent in its application as between major capex and base capex

(f) for each high value investment commissioned on or after the date of the guidelines, provide for Transpower to adjust a charge to reflect:

(i) any marginal saving to Transpower from a customer's credible commitment to reduce its demand for transmission services (if that commitment results in Transpower changing its investment plan resulting in a reduction in costs); or

(ii) any marginal increase in costs to Transpower from the customer's credible commitment to increase its demand for transmission services if that commitment results in Transpower changing its investment plan resulting in an increase in cost; and

(g) provide for Transpower to consult with interested parties about the areas that are likely to benefit from the investment, and the extent of any such benefit.

Features specific to the simplified method

7.38 The simplified method would be required to:

(a) to the extent practicable, be simple to apply and administer

(b) to the extent practicable, be simple for a party paying the charge to ascertain why the party is subject to the area-of-benefit charge

(c) for each eligible investment, identify each designated transmission customer that is expected to receive a positive net benefit from the eligible investment, unless doing so would unduly prejudice the requirements of paragraphs (a) and (b), in which case the method must identify the designated transmission customers that are expected to receive the majority of the positive net benefits

(d) to the extent practicable, to the extent practicable, provide for the allocation of charges to the beneficiaries identified in paragraph (c), so that each beneficiary is allocated the proportion of the charges that corresponds to the share that the beneficiary is expected to receive of the aggregate positive net benefits expected to be received by all identified beneficiaries

(e) to the extent that the method described in subclause (c) is not practicable:

(i) allocate charges to each identified beneficiary that is a load designated transmission customer on a physical capacity basis. The method for determining physical capacity would be the same as that used to determine physical capacity for the purposes of the residual charge

(ii) allocate charges to each identified beneficiary that is a generation designated transmission customer on the basis of each customer's average injection

(f) be phased in over as short a period of time as is practicable after the standard method takes effect.

Valuation of eligible investments

7.39 The Authority is considering options for valuing new investments that become subject to the area-of-benefit charge. The Authority's current preferred option is to value eligible investments commissioned after the date of the guidelines at replacement cost, as outlined in the next paragraph. However, as discussed below, the Authority does not have a firm view about adopting this approach. Hence, references in this paper to replacement cost (RC) and optimised replacement cost (ORC) should be read as indicative at this stage. At this stage, the Authority is proposing that the area-of-benefit charge would ordinarily be based on:

(a) replacement cost (RC) for assets in eligible investments commissioned after the date of the guidelines

(b) depreciated historical cost (DHC) for assets in eligible investments commissioned before the date of the guidelines.

7.40 For replacement cost, the expected life of the eligible investment would be determined by Transpower at the time of commissioning. The guidelines would provide that the charge for the eligible investment would be set so as to recover the cost of each asset in the eligible investment and the capital cost of holding the asset over its expected life (ie, maintenance aside, the present value of the charges would equal the initial cost of the eligible investment).

7.41 Force majeure aside, charges would apply in relation to the asset for the full expected life of the asset, no matter what its actual life turned out to be. If there was a force majeure event, the asset would be written down to its residual value and its life adjusted accordingly. (Presumably, in most cases, the value and life would both be zero.) Any loss in revenue would be recovered through the residual charge.

7.42 If Transpower undertook replacement, refurbishment or maintenance expenditure that is expected to extend the expected life of an asset, the replacement, refurbishment or maintenance investment would be capitalised and charged for as a new asset with a life equal to the now expected extended life of the asset.

7.43 Transmission customers would be able to apply to Transpower to have the value of an asset optimised to:

(a) optimised replacement cost (ORC), for assets in high value investments commissioned on or after the date of the guidelines

(b) optimised depreciated historical cost (ODHC), for assets in eligible investments commissioned before the date of the guidelines.

7.44 Optimisation to ORC would not be available for assets in low value investments, in keeping with the need for a simplified area-of-benefit regime for low value investments.

7.45 If a transmission customer applied for an asset to be optimised, Transpower would be required to optimise the asset:

(a) for assets in eligible investments commissioned before the date of the guidelines, if the ODHC for the asset is less than 80% of the DHC for the asset

(b) for assets in a high value investment commissioned on or after the date of the guidelines and before the investment has been commissioned for the period of time specified in the TPM, if the following two conditions are both met:

  (i) a single customer's disconnection from the grid causes the ORC for the assets to drop by more than 20%

  (ii) the ORC for the asset is less than 80% of the RC for the asset

(c) for assets in high value investments commissioned on or after the date of the guidelines and after the investment has been commissioned for the period of time specified in the TPM, if the ORC for the asset is less than 80% of the RC for the asset.

7.46 The period of time must be sufficient to ensure that the prospect of optimisation has a negligible impact on customers' motivation to seek new investment. The Authority's initial thinking is that the period of time in paragraph 7.45(b) and (c) would be at least 10 years. However, the Authority proposes to leave it to Transpower to specify a period in the TPM.

7.47 Transpower would determine the ORC or ODHC for assets in eligible investments as necessary in accordance with a method required to be set out in the TPM, which Transpower would propose to the Authority as part of its development of the TPM. One way to do this for ODHC would be to establish the full replacement cost of the current investment, and the corresponding optimised investment if it was constructed today, and then reduce the DHC by the ratio of the two.

7.48 Transpower would have the discretion to revise its calculation of ORC or ODHC over time, if demand for the asset changed by more than 20%. Transpower would also have the discretion to remove optimisation altogether if it is of the view that the criteria for optimisation are no longer met.

7.49 A party would be able to request that the value of an asset in an eligible investment be optimised, even if the investment's value has been optimised previously.

7.50 If charges in relation to an eligible investment are optimised to ORC or ODHC, any revenue in relation to the eligible investment that will not be recovered by the area-of-benefit charge as a result of the optimisation would be recovered through the residual charge.

Transpower may review application of charge

7.51 Transpower would be required to develop a method and process for:

(a) Transpower to review the application of the area-of-benefit charge for a high value investment if there has been a material change in circumstances, and adjust the charge if necessary

(b) Transpower to decide when a material change in circumstances has occurred. This must include consulting with interested parties about whether there has been a material change in circumstances before proceeding to review any area-of-benefit charge.

7.52 The Authority proposes that no such revisions to charges would be available for low value investments, in keeping with the need to have a simple area-of-benefit charge for low value investments.

7.53 The AoB charge would include an allocation for maintenance and operating expenses that is at least broadly cost reflective. Additional component 3 would provide for these expenses to be allocated on an actual cost basis.

7.54 Each of the key elements of the proposal is discussed in turn below.

A single main service-based charge for the interconnected grid

7.55 In the options working paper, the Authority considered adopting two service-based charges for the interconnected grid: the deeper connection charge and the area-of-benefit charge.

7.56 The Authority is now proposing only the area-of-benefit charge as a single main service-based charge for the interconnected grid. This is because the Authority is of the view that the area-of-benefit charge as a single main service-based charge would better promote the achievement of the Authority's statutory objective. In particular, the Authority's proposal would:

(a) yield net benefits substantially in excess of the $213 million estimated in the Oakley Greenwood cost benefit analysis, compared to the current TPM

(b) promote efficient investment in and use of the grid

(c) eventually apply the area-of-benefit charge across the interconnected grid and not just to a few such investments

(d) fully recover the costs of eligible investments (aside from optimised assets), so no revenue in relation to eligible investments would need to be recovered through the residual charge

(e) result in charges that better reflect the benefits to transmission customers from investments in the interconnected grid

(f) involve lower transaction costs than the area-of-benefit charge in combination with the deeper connection charge, or than the deeper connection charge by itself, as it would be simpler for Transpower to implement and administer, and simpler for transmission customers to understand and verify their charges

(g) avoid any risk of inefficiencies due to different charging approaches between interconnected grid assets.

7.57 The proposal to have a single main service-based charge for recovering the costs of the interconnected grid takes into account submissions that suggested that:

(a) the TPM should be simple and easily understood by customers and Transpower[191]

(b) interactions between two charges to recover the costs of non-connection assets were potentially problematic[192]

(c) having two main charges rather than a single charge would not necessarily lead to greater efficiency gains.[193]

7.58 Regarding (b), the Authority agrees that the combination of the deeper connection charge and area-of-benefit charge did have potential to cause

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191 Meridian (p.3), Transpower (CEG) (p.100), ENA (p.11), Carter Holt Harvey (p.4), MEUG (NZIER) (p.3)), Genesis (p.9), TNT2 (p.2), Contact (p.1).

192 PwC (p.7), Unison (p.13), Powerco (p.5-6), Transpower (CEG) (p.46), ENA (p.11), Trustpower (p.9).

193 Genesis (Castalia) (p.30), Buller (p.2).

problems, given the potential for the charging basis for an asset to change under the options considered in the options working paper.

7.59 Regarding (c), the Authority agrees that the efficiency gains that the two charges were targeting—principally promotion of efficient investment—could also be achieved with a single main charge. The Authority considers that, among the options it has considered, the area-of-benefit charge would best promote the Authority's statutory objective.

7.60 The Authority also considered applying just the deeper connection charge and a residual. This option is considered in chapter 9, along with other alternatives. Appendix E sets out in detail the deeper connection option considered by the Authority.

Charge would apply to eligible investments

7.61 As noted in paragraph 7.33, the area-of-benefit charge is intended to apply to assets in all new interconnected grid investments and to a selection of existing investments. However, as explained later in this paper, the area-of-benefit charge will be phased in for low value new investments.

7.62 The investments listed in paragraph 7.33(b) are existing investments approved after May 2004 and have a value of more than $50 million at the time of commissioning.

7.63 The rationale for the 2004/$50 million thresholds is that the efficiency gains from charging for historical assets (through improvements to durability and therefore investment efficiency) need to be traded-off against the additional costs of applying the area-of-benefit charge to historical assets. The $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 $50 million threshold still captures the bulk of the total value of existing assets that have been approved since May 2004, effectively addressing the durability issue.

7.64 Paragraph 7.33(c) also lists Pole 2, which was commissioned well before May 2004. Pole 2 has been included in the list of eligible investments so that all charges for the HVDC are service-based and cost-reflective, so that both HVDC poles are charged for on a consistent basis, and because the Authority considers the inclusion of Pole 2 is important to promote durability.

7.65 The Authority considered applying the area-of-benefit charge only to interconnected grid assets commissioned after the date on which the final guidelines are published. The Authority decided not to limit the area-of-benefit charge in that way, because under that approach the fundamental problems identified with the current HVDC and interconnection charges—ie, not service-based and not cost-reflective—would only be fully addressed over the very long term as assets are replaced. This is because the rate of new investment in the transmission grid may be relatively low in the short to medium-term. Therefore, there would be few assets that are charged on a service-based and cost-reflective basis.

7.66 Consequently, applying the charge only to new assets would not be likely to be durable because:

(a) it would not resolve the concern of some stakeholders with the current TPM that their charges do not reflect the underlying cost of providing them with transmission services and the benefits they receive

(b) regions that require major investments in the near future would pay for that major investment, while continuing to pay part of the costs of previous major investments from which they do not benefit.[194]

7.67 The Authority considers that transmission customers who may be required to pay the area-of-benefit charge will be incentivised to request information from Transpower about what their expected charges will be for a given investment and engage with the Commerce Commission's decision-making process to scrutinise the proposed investment. For base capex (which includes replacement and refurbishment expenditure as defined in the Capex IM) the incentives to scrutinise Transpower's plans would arise during the determination of the maximum allowable revenue (MAR) and each annual adjustment to the MAR.

7.68 In order to promote efficient investment, the charge would apply to replacement, refurbishment and upgrades, as well as new investment. In addition, projects and programmes for the replacement, refurbishment or upgrade of eligible investments may span more than one eligible investment. Therefore, the guidelines require the TPM to specify how the costs of those projects/programmes would be allocated.

7.69 For similar reasons, the Authority considers that the charge should be used to recover the costs of any payments by Transpower in respect of non-transmission solutions, such as payments to distributed generation for avoiding costs of transmission, as proposed in the consultation paper “Distributed generation pricing principles”. This is because recovery of the costs of these payments will help promote efficient investment in distributed generation where this is undertaken to avoid transmission investment, by promoting scrutiny of such proposals.

Standard method and simplified method

7.70 The guidelines would provide for a standard method to apply to high value investments. High value investments are eligible investments valued at $5 million or more at the time the investment is commissioned or completed. All the eligible investments listed in paragraph 7.33(b) are high value investments. The standard method would also apply to new eligible investments valued at $5 million or more. The simplified method would apply to new eligible investments under the $5 million threshold. The Authority considers that, for new eligible investments, the application of the area-of-benefit charge would produce efficiency gains in relation to both high value and low value investments. Applying the charge to both high value and low value investments would help promote efficient investment as it would:

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[194] Several submitters to the TPM options working paper made this point, including for example Orion (p.9) and Alliance Group (p.2).

(a) mean parties would have incentives to take into account the transmission investment implications of their own investment decisions and use of the grid

(b) promote improved scrutiny of almost all transmission investment.

7.71 The threshold of $5 million or more for high value eligible investments would cover all major capex under the Commerce Commission's Capex IM and any project or programme of base capex over $5 million.[195]

7.72 The Authority is proposing a $5 million threshold to delineate between investments for which there are likely to be net benefits from a more granular allocation of the area-of-benefit charge versus lower value investments for which this may not be the case. That is because, for low value investments, there is a greater risk that the transaction cost involved in a granular allocation of the charge may exceed the benefit from applying the charge.

Question 1: What threshold value should be used to determine which new investments should be subject to the standard area-of-benefit charge versus the simplified area-of-benefit charge? Please provide your reasoning and evidence in regard to the trade-offs mentioned above and any other factors you believe are material to this decision.

Both methods: Identification of areas-of-benefit and extent of benefit to each area

7.73 Both the simplified method and the standard method would need to provide for the identification of the areas-of-benefit (for the standard method) or the main areas-of-benefit (in the case of the simplified method).

7.74 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.

7.75 Both methods would need to allocate charges to an area-of-benefit based on the extent of the expected benefit to the area from the eligible investment. For eligible investments commissioned before 1 April 2019, expected benefits would be assessed as at 1 April 2019, for the expected remaining life of the investment. For all other eligible investments, expected benefits would be assessed at the date of commissioning or the completion date (as the case may be), for the expected remaining life of the investment.

Transpower to develop method

7.76 As Transpower has responsibility for the development of the TPM, the Authority considers it would be appropriate for Transpower to develop the methods for identifying areas-of-benefit and the extent to which each area benefits, for each of the standard method and the simplified method.

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[195] The threshold for major capex under the Capex IM is $20 million, but major capex excludes replacement and refurbishment expenditure as defined in the Capex IM. Major capex involves a specific investment proposal that is considered by the Commerce Commission. The major capex investment test requires Transpower to identify, and the Commerce Commission to assess, expected electricity market benefits and costs that are received or incurred by consumers of transmission services, during the calculation period.

7.77 As the party responsible for proposing and undertaking the investments, Transpower is best placed to identify the likely areas that would benefit from each investment and the relative value of those benefits. Transpower needs to determine aggregate net benefits in developing investment proposals, so it is appropriate that Transpower develops the methods for identifying areas of benefit for the purpose of applying the charge.

7.78 In order to identify areas of benefit, and determine the extent of each benefit, Transpower would need to identify all the benefits that the grid provides to customers. These include:

(a) transport of electricity for both load and generation

(b) for load, access to cheaper sources of electricity and the reliability of that access

(c) a backup source of electricity for load that is reliant on distributed generation

(d) for generators, access to higher paying distant customers and the reliability of that access.

7.79 The Authority has identified a number of methods for determining the areas of benefit from an investment, but it would be up to Transpower to identify a list of promising approaches and investigate them.

7.80 In regard to developing a standard method, the Authority is aware of the following potential approaches for identifying some or all of the benefits customers receive from investment in the interconnected grid:

(a) **Forecast SPD:** The Authority has modelled the area-of-benefit charge by applying the SPD method[196] on a forward-looking basis. This contrasts with previous applications of the SPD method, which were conducted on an historical basis. Adopting a forward-looking basis means expected beneficiaries and charges would be determined prior to the investment being commissioned; and this determination would not change unless the charge was re-calculated based on new information. If the SPD method were used, the benefit calculated through the method should not be capped, as the benefit would need to reflect benefits over the lifetime of an investment.

(b) **Economic model** (as explored in the October 2012 issues paper):

(i) **Hogan method:** This approach would estimate the benefits to parties from transmission expansion by considering the electricity exports and imports enabled by the investment. It uses transmission planning and dispatch models to estimate expected benefit.[197]

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[196] Refer Appendix E, Using the SPD method to apply beneficiaries pay, Transmission pricing methodology review - issues and proposal, 10 October 2012.

[197] See Hogan, WW, Transmission Benefits and Cost Allocation, 31 May 2011, available at: http://www.hks.harvard.edu/hepg/Papers/2011/Hogan_Trans_Cost_053111.pdf.

(ii) **Trade restriction method**: This approach would treat assets as a quota restricting trade between regions and identify beneficiaries from the trade restrictions.

(c) **Area-of-influence method:** This method is based on the marginal use of the network. Unitary increases of generated or demanded power are successively applied to each grid node to determine the area of influence, defined as the set of lines in which the corresponding power flow variation is positive. The share of a user on a certain line is obtained through the average of its participation in all the states analysed, compared with the participation of the other users. This is a user-pays ex-ante approach. This method is applied in Argentina and a similar method is applied in Chile.[198]

(d) **Balanced scorecard method:** A balanced scorecard approach could be developed to provide a score and weighting for each type of benefit. The approach would be objective if the scores were calculated based on a predetermined methodology.

Question 2: Bearing in mind that it is proposed that Transpower develop a method of determining the areas of benefit, which of the above methods do you think should be used to determine the areas of benefit from high value investments in the interconnected grid?

7.81 In regard to developing a simplified method for low value investments, the Authority has identified the following potential approaches which Transpower could consider:

(a) the approach proposed for the area-of-benefit charge in the TPM options working paper, in which the charge would apply to parties in the area where the primary benefits (or benefits without which the investment would not have been made) of the investment were expected to accrue.

(b) applying the charge to the transmission customer or customers receiving transmission services at nodes at which the investment occurred (in the case of equipment like transformers) or to the transmission customer or customers receiving transmission services at nodes between which the investment occurred (in the case of investment in lines and towers, for example)

(c) applying the charge to transmission customers receiving transmission services in the transmission planning region in which the investment was made.

Question 3: Bearing in mind that it is proposed that Transpower develop a method for determining the areas of benefit, which of the above methods do you think should be used to determine the areas of benefit from low value investments in the interconnected grid?

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[198] See Compass Lexicon on behalf of Vector, page 36.

Robustness concerns

7.82 Some submitters on the options working paper were concerned that the identification of areas of benefit by Transpower would be subjective and reliant on Transpower's discretion. The Authority appreciates those concerns and is therefore proposing to make minimal discretion a key factor in the design of the standard method for determining areas of benefit.

7.83 However, the Authority is also of the view that perfection and total objectivity are not features of workably competitive markets and should not be expected from the methods for assessing areas of benefit. Even with a high degree of approximation, the area-of-benefit charge would still provide much better incentives for grid users than would be the case under the status quo (ie, the current TPM as amended in accordance with Transpower's operational review).

7.84 As discussed in Chapter 12, Transpower would be required to consult on the methods for identifying areas that would benefit from eligible investments, as part of its development of the TPM. Hence, stakeholders would have an opportunity to assist Transpower to develop suitably robust methods.

7.85 Further, in relation to the standard method, the Authority is proposing that Transpower consult with interested parties about whether the areas identified would in fact benefit from the investment, and the extent of the benefits. This consultation should help reveal information relevant to establishing the true economic benefits of the investment for each area or node, which may feed into any consultation Transpower undertakes regarding the total economic benefits of the investment.

7.86 One of the main arguments against the area-of-benefit charge has been that, unless a robust way of identifying beneficiaries can be identified, the charge would incentivise lobbying by parties to avoid those parties being identified as beneficiaries.[199] However:

(a) Parties will have a countervailing incentive because, if they claim not to benefit from an asset, Transpower may decide not to proceed with the proposal.

(b) As the methods will be part of the TPM, the only way they could be changed would be through changing the TPM, which the Authority would only approve if doing so promoted the Authority's statutory objective.

(c) In most cases a party would have to show that its benefit is somehow lower than the benefit received by other parties in the relevant area. Other parties in favour of a proposed investment would have incentives to put forward information to support the opposite case to avoid paying a higher share of the costs of the investment that benefits them.

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[199] For example, in submissions on the options working paper: PwC (p.7), Fonterra (p.5), Transpower (CEG) (p.81), Trustpower (Bushnell) (p.5), ENA (p.10), Powerco (p.5), Westpower (p.7), Trustpower (p.17).

Both methods: Allocation to generation and load customers based on aggregate expected net benefits

7.87 The standard method and simplified method must each allocate charges as between generation and load customers in an area-of-benefit so that each group is allocated charges that correspond to the proportion of the aggregate positive net benefits that the group is expected to receive from the eligible investment.

Standard method: allocation within an area-of-benefit based on each beneficiary's expected positive net benefit

7.88 To the extent practicable, the standard method would require charges for an area-of-benefit for a high value investment to be allocated to transmission customers in that area-of-benefit so that each customer is allocated the proportion of the charges that corresponds to the proportion of the aggregate positive net benefits that it is expected to receive from the eligible investment.

7.89 This characteristic is important for promoting efficient investment and efficient operation. As explained in chapter 5, charging parties according to their expected benefit over the lifetime of the investment, and no more, promotes efficient investment. That is because grid users would face the incentive to make efficient location and investment decisions, which are essential for efficient use of the grid, and in turn are necessary for optimal grid investment.

7.90 The area-of-benefit charge proposed in this paper differs from the area-of-benefit charge that was analysed in the options working paper. That approach applied charges to just the primary expected beneficiaries of the investment, ie, the parties expected to receive the benefits from the investment without which the investment would not have been made.

7.91 For example, in the case of the NIGU project, the previous proposal for area-of-benefit charges would have resulted in charges to upper North Island consumers only, as the NIGU project was undertaken to cater for growth in upper North Island demand.

7.92 The area-of-benefit charge would apply to all expected beneficiaries from an investment. Accordingly, in the above NIGU example, charges would apply to all expected beneficiaries, which include:

(a) upper North Island load, benefit from continuing to have their demand for transmission services met in the face of growth in load

(b) central North Island load, who benefit from improved reliability

(c) central North Island generation, who are able to export more electricity to the upper North Island

(d) load and generation across the grid who benefit through reduced losses.

7.93 Also, the charges each customer faces should reflect its share of the benefits that all beneficiaries would be expected to receive. This would mean, in the NIGU example, that upper North Island customers would pay the most towards the costs of the NIGU project, but that some of the costs would also be borne by the other customers expected to benefit from the investment.

7.94 The Authority has considered submissions that the area-of-benefit charge should include the expected private dis-benefits of the investment as well as the expected private benefits.[200] The Authority considers that charges should be set on the basis of net benefits from the investment, ie, benefits minus dis-benefits. This would mean that the area-of-benefit charge would only apply in respect of an area that is expected to receive net benefits from the investment.

7.95 The charge would not involve compensating parties that suffered dis-benefits from an investment. Compensating parties facing net dis-benefits would:

(a) open the regime up to unlimited rent-seeking, as there is no limit to the size of dis-benefits, whereas the benefits only need to be higher than the costs for the charge to apply

(b) increase the rate of the charge to recover both Transpower's investment costs and any compensation paid to parties suffering net dis-benefits, which increases the risk of inefficient behaviour to avoid the charge.

7.96 Depending on the method chosen for determining the areas of benefit, there is some remaining risk that some parties may face charges that exceed the private benefit they will receive, at least in the short-term. In part, this would be because the charge would be set according to expected benefits, not actual benefits. Charging according to expected benefits reduces the likelihood of the charge introducing distortions to grid use, as the charge is calculated on the basis of predicted grid use rather than actual grid use. However, it does mean there is a possibility that charges will not accurately reflect the shares of benefit actually received. The Authority considers this is a necessary consequence of the need to ensure that the area-of-benefit charge does not distort use of the interconnected grid. However, as discussed in a later section of this chapter, the Authority is proposing that provision be made for the charge to be recalculated where there is a material change in circumstances, and a significant divergence between expected and actual benefits in regard to high value investments is an example of such a material change.

7.97 Aspects of the area-of-benefit charge for high value investments have been designed to minimise the chance of charges exceeding net private benefits. This includes allocating the charge to both load and generation to the extent they are expected to benefit from an investment, allocating the charge to all expected beneficiaries from an investment, and, if certain criteria are met, allowing assets to be optimised. These features are discussed in more detail below. Further, even if the charges for a high value investment exceed the benefits stemming from the investment in some years, over the lifetime of the investment total charges should be less than total benefits, if the investment is economic.

Standard method: allocation to load based on physical capacity to the extent that the expected positive net benefits approach is not practicable

7.98 The Authority is proposing that, to the extent that it is not practicable to allocate area-of-benefit charges for high value investments to load payers based on each customer's expected positive net benefit, charges would be allocated to load payers within an area-of-benefit based on each customer's physical capacity.

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[200] For example, see the following submissions on the TPM options working paper: Meridian (p.27), Orion (p.7).

7.99 It is proposed later in this chapter that the residual charge be allocated on physical capacity. The method of calculating physical capacity for that purpose is described under that heading. It is proposed that the same method be used to calculate physical capacity for the purpose of allocating area-of-benefit charges.

7.100 Essentially, a customer's physical capacity is calculated on its historical physical capacity so that the charge is calculated in a way that is not affected by their current use or current capacity. As a result, customers have very little incentive to alter their current behaviour in an attempt to avoid the area-of-benefit charge.

7.101 In contrast, if current physical capacity was used, customers would have an incentive to alter their behaviour. If the physical capacity measure was based on current transformers, for example, a customer may be able to reduce those charges by replacing the transformers with lower capacity equipment (if the customer owned the transformers) or seeking replacement by Transpower (if Transpower owned the transformers). The customer would have the incentive to do so if it could profitably replace the physical capacity with distributed generation or demand response capacity. Incurring these costs would be wasteful when there is plenty of spare transmission capacity.

7.102 If area-of-benefit charges for large grid investments are allocated on the basis of each customer's physical capacity, it increases the risk that a customer's share of the additional transmission charges could exceed their share of the cost of the upgrades. This would create incentives for inefficient behaviour. For example, load customers might be encouraged to build or contract for alternatives even when those options are more costly than upgrading the lines or transformers feeding the customers. This is one of the reasons that the Authority prefers, to the extent practicable, the more efficient approach of allocating area-of-benefit charges based on share of expected positive net benefits.

7.103 In conclusion, allocating area-of-benefit charges to load based on their share of expected benefits is most consistent with a service-based and cost-reflective approach to pricing, and is likely to be reasonably efficient. However, if that approach is not practicable, then allocating area-of-benefit charges in proportion to an historical measure of physical capacity is likely to be the next best approach.

Standard method: allocation to generation on average injection basis if expected positive net benefit approach not practicable

7.104 The Authority is proposing that, to the extent that it is not practicable to allocate area-of-benefit charges to generation payers based each customer's expected positive net benefits, charges would be allocated to generation on the basis of each customer's average injection. This approach would be relatively neutral in its economic incidence and in the incentives it creates between different types of generation.[201]

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[201] The economic incidence of a charge is the portion of the charge borne by the party that is required to pay the charge. For example, businesses in New Zealand are required to pay goods and services tax (GST). Generally, an increase in GST results in the full amount being passed onto consumers in the form of higher prices. The economic incidence on businesses is zero if the GST cost is fully passed through to consumers, even though the legal incidence is 100% on businesses.

7.105 An average injection allocation for generation is likely to be less distortionary than an anytime maximum injection (AMI) or a capacity-based allocation. As Transpower identified in its TPM operational review, allocating charges to generators on a capacity basis would inefficiently disincentivise peaking and intermittent generation.

7.106 Some submitters were of the view that an average injection (MWh) allocation on generation would be inconsistent with a capacity allocation on load, and could be distortionary.[202] However, the Authority is proposing different allocators for load and generation as each type of party has different characteristics. Further, as discussed above, the charges for high value investments would be apportioned to aggregate load and aggregate generation in proportion to the aggregate net benefits to generation customers and load customers. The Authority believes this approach should avoid any distortions from applying different methods within each type of beneficiary.

7.107 The theoretically efficient means of addressing the problem of distortion to behaviour from the charge would be to allocate charges to generation on a Ramsey pricing basis. This would result in low charges for very price sensitive generators, such as peaking generation, and higher charges to generators whose output varies little with price, such as geothermal and run-of-river hydro generation. However, the Authority considers that Ramsey pricing could lead to inefficiencies in new generation investment. In any event, it is impractical because price elasticities of demand for transmission services would need to be estimated for each generator. It would be difficult to obtain robust estimates, and the true elasticities for each generator are likely to vary significantly over time.

7.108 Other submitters were concerned that generators are likely to pass through average injection (MWh) charges to customers, resulting in inefficient dispatch.[203] The Authority considers that the extent to which generators would be able to do so is limited since not all generators would face the same area-of-benefit charge, or have the same ability to pass on charges. However, the Authority acknowledges there is likely to be some inefficiency from allocating the area of benefit charge to generators on an average injection. That is one reason why it would prefer to allocate the charge based on expected net private benefit. However, the Authority is of the view that the inefficiency is likely to be less than any of the other options available. Experience with the HVDC charge suggests that South Island generators have had limited ability to pass on HVDC charges. The outcome from applying an average injection area-of-benefit charge to a subset of generators could be similar.

7.109 Another alternative would be to apply charges to generators on a physical capacity basis with a discount for low capacity factor plant, such as peakers and wind. This could limit the incentives on generators to inefficiently avoid the charge. The Authority is not proposing this alternative as it would affect incentives on generators to invest in capacity, and including a discount for low capacity factor plant should result—if the discount factor was accurate—in similar

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[202] For example, Transpower (CEG) (p.5-6), EPOC (p.11-12).

[203] For example, Transpower (CEG) (p.79).

outcomes to allocating charges on an average injection basis. Further, the capacity factor adjustment for different generators would be a matter of judgement, and so to some extent arbitrary, if it were not itself based on average injection.

Standard method: Area-of-benefit charge to provide a marginal price signal for new investments

7.110 Under the area-of-benefit charge, each customer would be charged its share of the cost of any new high value investment proposed by Transpower based on the benefit it was forecast to receive from the investment. This means that each customer faces the average cost per unit of benefit it is expected to receive from the new asset, and collectively customers face the full price of the asset.

7.111 However, if, before an investment, a customer credibly commits to reducing its demand for access to transmission services in response to this price signal and Transpower changes its investment plans as a consequence, a resource saving arises. That saving is the marginal cost of transmission services. The marginal cost of transmission services is lower than the average cost because of economies of scale. The Authority proposes that, in such a case, the TPM would provide that Transpower could make an adjustment to a customer's charges to reflect the marginal saving to Transpower from the customer's reduced demand.

7.112 Transpower could also make a marginal cost adjustment if, conversely, a customer credibly commits to increase its demand for transmission services.

7.113 No such adjustments would be available for low value investments, as these investments need to be subject to a simplified regime.

7.114 Relying only on an average cost-based price signal means that the customer faces inefficient incentives in deciding how much transmission services to purchase access to.[204]

A hypothetical example

7.115 Consider the following hypothetical example. Suppose Transpower is considering the installation of a new 1000 kVA transformer costing $2,000 to service five customers. The average cost per kVA is therefore $2/kVA.

7.116 Assume for the purpose of this example:

(a) that transformer capacity is continuously scalable but that there are economies of scale. Specifically, assume that the price of capacity can, pre-investment, be approximated by a fixed cost of $1,000 and a variable cost of $1/kVA.

(b) that the benefit a customer receives is proportional to its peak capacity use.[205]

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[204] The issue discussed here arises with any regime where there is shared use of an asset, the asset exhibits economies of scale and there is full cost recovery. For example, it arises with the current connection charge for shared connection assets because costs are shared in proportion to shares of demand (for load) and injection (for injection customers).

7.117 Suppose also that Transpower assesses that the five customers would benefit equally from the transformer, based on their likely use of it. That is, each user has a likely peak load of 200kVA. Transpower therefore proposes to install the transformer and charge each customer a fixed annual fee which has a present value of 200kVA*$2.00 = $400.

7.118 After Transpower publishes its proposal, but before the investment is made, one of the customers (call this customer "customer 1") commits to installing distributed generation to reduce its peak load by 50%, to 100kVA. This would reduce the size of the transformer Transpower requires to 900kVA. This transformer would cost $1900, or $2.11/kVA. On that basis, customer 1 proposes that its share of the transformer's cost be reduced to 100kVA*$2.11 = $211,[206] saving the customer $189.

7.119 However, the saving to Transpower from installing the smaller transformer is the reduction in the variable cost of the investment, which is 100kVA * $1/kVA = $100. That is, the reduction in capacity is inefficient if the opportunity cost to the customer of reducing its peak capacity is between $100 and $189. This is because the customer has an incentive to reduce its demand for capacity even though the social cost of doing so exceeds the social benefit of reduced capacity.

7.120 The only way to avoid the inefficient incentives that lead to this outcome, while still recovering the full cost of the asset, is to compensate the customer for the reduction in its demand for capacity at the marginal cost of capacity, $1/kVA, not the average cost.[207]

7.121 One way to implement this would be for Transpower, when it first announced a proposed high value investment, to also announce its assessment of:

(a) which customers would benefit from the investment

(b) how much each customer would benefit from the investment

(c) the charge each customer would face for the investment

(d) the effect on the cost of the investment (and so the total charge for the investment) if customers altered the benefits they were seeking from the investment.

7.122 If a customer decided to reduce its demand for capacity, and Transpower scales back the investment, Transpower would reduce the customer's charge by the cost savings it makes. The reduction in the customer's charge per unit of capacity reduction would be less than the average cost per unit that the customer pays for the asset. This is reasonable as the intention is to allocate charges according to benefits, and logically, the capacity that the customer is giving up is

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[205] This assumption makes the discussion more concrete and the potential distortion starker. Note also that there are a number of other implicit simplifying assumptions—eg, that every customer's peak use occurs at the same time, so the sum of peaks equals the capacity. These assumptions simplify the presentation but are not fundamental to the argument.

[206] Note that this implies that every other customer's charge would go up to $422. This is because the price reduction customer 1 is seeking for reducing their demand is more than the marginal saving from reducing the capacity of the transformer.

[207] Adopting this approach also means that the charge to other customers does not change as a result of this customer's reduction in demand for capacity.

the capacity that benefits it least—so the marginal reduction in benefit is less than the average. In other words, this aspect of the TPM would reflect a form of Ramsey pricing.

7.123 However, under this approach, different users could face different prices for the same assessed benefits. For example, customer 1 would face a charge of $300 for their 100kVA ($400 for the initial 200 kVA less 100kVA x $1/kVA for the reduction), whereas a customer who was originally assessed as having a demand for capacity of 100kVA would face a charge of $200 (100kVA x $2/kVA).

7.124 This would not be inefficient provided that every customer pays between incremental and standalone cost. Nor would the change affect the other parties assessed as benefitting: the price they pay does not alter, and they could also reduce their price by reducing their demand for the asset in the same way.[208]

Incentive issues raised by the marginal benefit adjustment mechanism can be addressed

7.125 The area-of-benefit charge provides incentives for customers that benefit from a proposed investment proposal to seek to:

(a) Minimise Transpower's assessment of the benefits they receive from the proposal. This incentive is tempered but not eliminated by the risk that this will encourage Transpower not to proceed with the proposal or to downgrade the capacity or quality of the proposal.

(b) Maximise Transpower's assessment of the benefits that other parties receive from the proposal.

7.126 This is because in both cases, the customer's area-of-benefit charge reduces as their share of the total assessed benefits of the project reduces.

7.127 In order to limit this sort of rent-seeking and the associated transaction costs, it would be desirable for Transpower to take an objective and pragmatic approach to assessing benefits.

7.128 The approach outlined here potentially reduces the incentives outlined in paragraph 7.125 for the customer to understate their benefits, since they benefit only by the marginal change in cost of the project rather than the average change. It nevertheless continues to pay them to understate their benefits and overstate others' benefits for the reason outlined in paragraph 7.125.

7.129 These problems arise with any approach that endeavours to charge customers the SRMC for use of the grid and an access fee related to the cost of new investments that is unrelated to use. In particular, reviewing the access charge based on actual benefit the customer derives from the new asset after it is constructed, would turn the access fee into a usage charge and reduces the efficiency of the pricing regime.

7.130 There are, however, a number of ways these problems would be mitigated:

[208] The other customers' charge would change, however, if the benefits they receive change as a result of customer 1's decision to reduce their demand for capacity. This could happen for example if customer 1's decision led to a change in nodal prices.

(a) The area-of-benefit proposal for the standard method must limit the need for Transpower to exercise discretion. This means that customers have limited scope to distort Transpower's assessment of their future benefit from the asset.

(b) The policy (discussed later in this chapter) to revisit the charges when there is a material change in circumstances reduces the expected benefits to customers of not revealing major planned changes in use to Transpower during the investment decision-making process.

(c) If a customer asserted that its benefit from the project was less than Transpower had assessed, the guidelines would provide that Transpower would be required to change the customer's charge if it was satisfied that the customer had in fact significantly changed the benefits it would gain from the asset. In particular, the customer would need to provide a clear and credible commitment that its use would indeed change (eg, a signed contract that it was installing distributed generation) before Transpower would reduce the customer's charge.

(d) Customers would have the incentive to request identification of benefits and have an incentive to comment on the benefits that other customers assert they would receive (since they have an incentive to seek the highest assessed benefit possible for other customers).

(e) Customers collectively are somewhat constrained by the wish to have the project go ahead if its benefits exceed its costs.

Simplified method

7.131 For transmission charges to be service-based and cost-reflective it is important that, as much as practical, all parties benefiting from investments face the costs of those investments. The proposal to apply a simplified approach for low value investments is likely to result in an area-of-benefit charge for low value investments that would be less service-based and less cost-reflective than if the standard area-of-benefit charge applied to those investments.

7.132 However, the simplified area-of-benefit approach retains strong incentives on payers to contest the need for each investment, as doing so could reduce their charges appreciably. This is likely to be particularly important for promoting efficient decision-making when transmission customers (eg, distributors) have more efficient alternatives available to them.

7.133 Overall, the simplified approach forgoes some of the efficiency benefits of the standard approach, but it avoids high administration and transaction costs for low value investments, which is a resource saving for transmission customers, and ultimately for electricity consumers.

7.134 Based on information provided by Transpower in relation to the SPD charge proposed in the first issues paper,[209] plus information provided to the Authority by Transpower on its current investment programme, the Authority expects there to be a relatively large number of small investments by Transpower each year.

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[209] See in particular: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/spd-pricing-asset-groups.xlsx

Hence, the Authority considers that applying the standard area-of-benefit charge to low value investments may be very costly.

7.135 Rather than require Transpower to propose a simplified area-of-benefit charge for low value investments, the Authority considered allocating the cost of those investments to the residual charge. This would have spread the cost of low value investments across all load customers, rather than recovering them from the parties expected to receive the majority of the positive net benefits.

7.136 However, the approach under the residual charge would introduce strong incentives for transmission customers to seek to have investments from which they benefit sized below the $5 million threshold, such as by breaking investments up into to smaller tranches. This is likely to create significant inefficiencies as the benefits of larger-scale investment would be forgone.

7.137 These boundary issues are common to pricing and taxation, and can be expected to be particularly acute for situations where the boundary is between highly targeted charges (ie, the standard area-of-benefit charge and the connection charge) and highly spread charges (ie, the residual charge). Adopting a simplified area-of-benefit approach reduces the sharpness of the boundary between low and high value investments, as compared with not adopting a simplified approach.

7.138 Accordingly, the Authority's preference is for the coverage of the area-of-benefit charge to be across as broad a base as possible. Applying the area-of-benefit charge to both low and high value investments would help promote efficient investment as it would:

(a) mean parties would have incentives to take into account the transmission investment implications of their own investment decisions and use of the grid

(b) promote improved scrutiny of almost all new transmission investment.

Phasing-in the simplified area-of-benefit charge

7.139 The Authority is proposing the standard area-of-benefit charge be implemented in 'one go' as it will initially apply to around only 20 investments. There are, however, a large number of Transpower investments below $5 million in value. Implementing the simplified charge in 'one go', and in parallel with the standard charge, may impose a high administrative burden on Transpower and transmission customers.

7.140 Although delaying the implementation of the simplified approach delays efficiency gains, the Authority believes it may be more effective and less risky to first implement the standard charge, address any customer and IT-related issues with it, and then phase in the simplified charge over as short a period of time as is practicable after the standard charge has 'bedded in'.[210] Because the residual charge recovers all revenue not otherwise recovered by the TPM (or a lesser amount determined by Transpower) any revenue foregone from phasing in the

[210] The Authority has adopted these assumptions in its modelling of the area-of-benefit charge discussed below, which means the simplified area-of-benefit charge is not expected to raise any revenue over the modelled period.

simplified area-of-benefit method would be recovered through the residual charge.

7.141 The above transition approach is only one approach. Transpower will need to determine the resources it needs for implementing the area-of-benefit charge, and consider the costs and risks of various implementation approaches. The Authority is therefore proposing that the draft guidelines require the TPM to include a requirement to phase in the simplified area-of-benefit charge over a short a time period as is practicable after the standard method takes effect.

Valuation of assets in an eligible investment

RC for new eligible investments unless optimisation is granted

7.142 The Authority proposed in the options working paper to charge on the basis of DRC to address the issue of premature, inefficient investment. At this stage, the Authority now considers that RC charging for the expected life of each eligible investment could be preferable to DRC, because it would:

(a) promote efficient replacement and refurbishment

(b) ensure that charges are consistent with service-based charging, and promote efficient use of each investment.

7.143 RC charging is more consistent than DRC with what occurs in workably competitive markets for utility-type services. For these types of services, aesthetics are largely irrelevant to the benefits customers receive from the service, and therefore charges do not reflect the age of the asset providing the service.

7.144 The area-of-benefit charge would be calculated based on the expected life of the eligible investment.[211] The expected life of the investment would be determined by Transpower at the time of commissioning. The guidelines would provide that the charge for the eligible investment would recover the cost of each asset within that eligible investment; and the capital cost of holding each asset over its expected life (ie, maintenance aside, the present value of the charges would equal the initial cost of the eligible investment). Maintenance would be charged separately.

7.145 If it turned out that the actual life was shorter— such that there was a loss on disposal and replacement of the eligible investment—customers would continue to be charged for the existing asset until the end of its originally estimated life. Thus if the asset was replaced, they would be paying charges for both the new and the old asset for a period. This adjustment would not, however, be made if the replacement was triggered by a force majeure event—eg, an explosion or earthquake. Conversely, if it turned out that the actual life of the eligible investment was longer, the capital charges would be reduced to zero (ie, the asset would be deemed to have a book value of zero for the purpose of

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[211] This is true by construction since the area-of-benefit and connection charges are both intended to be cost-reflective. This means that the charges for an asset should recover the full present value of the cost of the asset over its life. In principle, different ways of valuing the asset should only result in a different time profile of the charges. The total nominal value of charges recovered is also likely to differ, but only because of discounting.

calculating those charges) at the end of its initially expected life in calculating the area-of-benefit charge.

7.146 The purpose of adjusting the book value at the end of the eligible investment's initially expected life is so that, over time—force majeure events aside—the prices charged for access to the asset accurately reflect its cost, and they do not over or under-recover that cost.

7.147 If Transpower undertook replacement, refurbishment or maintenance expenditure that is expected to extend the life of an asset beyond its initially expected life (or if it has been previously re-estimated as a result of previous expenditure, the re-estimated life), Transpower would treat the replacement, refurbishment or maintenance expenditure as expenditure on a new asset in the year it was incurred, with the asset having a life through to the new extended life of the asset.

Discussion: alternatives to RC that the Authority is considering for new eligible investments

7.148 Having discussed the case for applying the RC valuation method to new eligible investments, the Authority has concerns about this approach:

(a) *Practicality*: the RC approach may be expensive to implement, and ongoing adjustments to RC can be contentious if RC values increase greatly over time.

(b) *A potential boundary problem*: adopting the RC approach for new eligible assets could create inefficient incentives for transmission customers to prefer connection investments over investments in the interconnected grid or vice versa, because the asset return rate component of the connection asset charge involves valuing connection assets on an AHC (pooled DHC) basis (as discussed earlier in this chapter).

7.149 The Authority seeks submitter views on the practicality of adopting the RC approach, and in particular any experience with implementing and operating an RC approach over a reasonable period of time. For example, the Authority understands that RC values depend greatly on choices about whether all components in an investment are assumed to be replaced ‘in one go’ or whether the assumption is that components are replaced ‘one-by-one’ as they come due for replacement.

7.150 In regard to the potential boundary problem, charges under alternative asset valuation methods should, in principle, provide the same present value of cash flows if the future is known with certainty, including in regard to future regulated valuation methods. However, this may not apply in practice. For example, regulated businesses are typically concerned about regulatory uncertainty and prefer valuation methods that bring forward the cash flows from their investments. Conversely, the customers of regulated services prefer to defer their payments to the end of the asset’s life.

7.151 As the cash flows under an RC approach differ from a DHC approach, adopting an RC approach for new eligible assets for the area-of-benefit charge differs from the approach already in place for new connection assets, which has the potential to create inefficient incentives for parties to prefer investments in connection assets over interconnected assets or vice versa.

7.152 The Authority has considered the following options to address the concerns outlined in paragraph 7.148:

(a) Option 1: Require Transpower to value new connection assets on the same basis as new non-connection assets. This approach would eliminate the boundary problem discussed above, and it would increasingly convert connection charges to a fully service-based approach.

(b) Option 2: Apply the connection asset valuation method to new area-of-benefit assets. This uses average historical cost (AHC) and was discussed in detail in paragraphs 7.18 to 7.26 in regard to connection charges. As with option 1, this approach would also eliminate the boundary problem. However, the pooled approach used for connection assets works well for a pool of assets in an approximately steady state, such as is the case for the connection pool (ie, additions to the connection pool are relatively constant from year to year). But a pooled approach doesn't translate readily to the situation where the pool of new area-of-benefit assets begins with one asset and grows over a long period of time. In this case, the first entrants into the 'area-of-benefit' pool will continue to pay high charges because the average age of the pool would remain low for a long period of time until the pool reached a steady state.

(c) Option 3: Apply the DHC valuation method to assets in new eligible investments, in the same way that the Authority is proposing to apply it to assets in existing eligible investments. Adopting the DHC approach for assets in new eligible investments runs counter to the approach in this paper to require service-based charges: it would result in less stable charges for individual transmission customers. Furthermore, it would not address the boundary problem, because the charges would be based on AHC for connection assets and assets in DHC for new eligible assets.

(d) Option 4: Use historical cost (HC), or historical cost indexed to inflation, as a proxy for replacement cost. This option would maintain the service-based feature (ie, steady price for steady service levels) the Authority is seeking to achieve. Furthermore, as discussed earlier, in principle the present value of charges should be the same as under the other approaches discussed. Both historical cost approaches would be low cost to implement and operate, and if indexation was adopted this should result in non-contentious adjustments to asset values and area-of-benefit charges. The boundary problem discussed above would also seem to be less problematic under this option.

7.153 On balance, the Authority believes at this stage that the RC approach is likely to be the best approach for new eligible investments. However, the Authority does not have a firm view about this and is also attracted to the historical cost or indexed historical cost approaches.

7.154 The Authority would particularly appreciate submitter views on the valuation issues and options discussed above.

ORC for new investment on application by a customer

7.155 Subject to the above discussion about RC, the proposed guidelines also provide for an adjustment to ORC for an asset in a high value investment. Parties must apply for optimisation, which will only be granted if ORC for the asset is less than 80% of the RC for the asset. In addition, for a period of time specified in the TPM (the Authority's initial view is that a period of at least 10 years would be appropriate), after an eligible investment asset is commissioned, optimisation would not be available unless the following conditions are met:

(a) a single customer disconnects from the grid, causing the ORC for the asset to drop by 20% or more, and

(b) the ORC for the asset is less than 80% of the RC for the asset.

7.156 For example, suppose that a customer served by an eligible high value investment disconnected from the grid for some reason. In a workably competitive market, the contractual terms between the supplier of services (Transpower in this case) and the customer would determine whether the supplier or the customer in question bears the loss on the eligible investment that is stranded or significantly underutilised as a consequence of the disconnection. It would be unusual for other customers of the supplier to bear any of the cost.

7.157 However, under Part 4 of the Commerce Act, Transpower is able to fully recover its MAR, including where assets have been stranded.

7.158 The Authority has adopted the optimisation proposal:

(a) to reflect the service provided where there has been a material change in circumstances, such as significant technological development or a substantial reduction in demand, that is likely to be sustained

(b) to efficiently manage the risk of asset stranding, and so reduce investment uncertainty, by providing all customers with an assurance that there is a limit to how much direct additional cost they will have to bear because other customers change their use of the eligible investment.

7.159 The different treatment before and after the period of time specified in the TPM is intended to ensure that customers do not seek to have new investments “gold plated” in the knowledge that optimisation is available. The period of time must be sufficient to ensure that the prospect of optimisation has a negligible impact on customers’ motivation to seek new investment.

DHC/ODHC for assets in existing eligible investments

7.160 The Authority has proposed to base charges for assets in existing eligible investments on DHC or ODHC because:

(a) There are limited efficiency gains from using RC for existing assets.

(b) The preservation of DHC for existing assets provides a gradual transition to RC over time as existing assets are replaced.

(c) Charging RC for existing assets may lead to:

(i) the recovery of more than the RC (potentially up to double recovery) on some older assets

(ii) substantial changes in charges for some customers as at the implementation date.

7.161 In particular, moving from DHC to RC for customers with heavily depreciated assets would result in those customers being charged more than the full cost of the assets they use, seriously breaching the principle of cost-reflectiveness discussed in chapter 5. This is because the costs of heavily depreciated assets would have already been largely recovered through existing charges. In addition, they may affect perceptions of fairness, and so reduce the durability of the proposed TPM. As with other factors that could undermine durability, this could give rise to uncertainty and therefore adversely affect investment efficiency.

7.162 The Authority has taken into account submissions that charges for historical assets should be on the basis of the optimal assets that would be used to supply the customer rather than the actual asset in place.[212]

7.163 The above discussion on optimising the value of new assets also applies to the treatment of existing assets. In a workably competitive market, if a supplier and its customer had agreed to contractual terms that involved the customer paying the cost of the asset over its life consistent with DHC, they would not expect those charges to increase simply because the supplier stopped supplying another customer.

7.164 As a result, the Authority has decided that optimisation to ODHC will be available for existing assets on the same basis as optimisation is available for new assets, with one difference. That is that the tighter eligibility criteria would not apply before the period of time specified in the TPM has expired. This is because customers' future behaviour cannot influence investment undertaken in the past.

Review of the charge

7.165 In workably competitive markets, parties to long-term contracts typically include provisions to deal with material changes of circumstances. Often those provisions require the parties to work in good faith to re-establish the commercial basis of their agreement. Although the presence of such provisions can create incentives for opportunistic behaviour, carrying on with manifestly inappropriate arrangements can also create inefficiencies.

7.166 Whatever method is used to calculate the benefits for areas (and customers within those areas), a significant divergence between actual and expected benefits could arise over time. The greater the divergence, the less the charge would remain service-based and cost-reflective, potentially undermining the durability of the area-of-benefit regime. In addition, a review process would reveal the true economic benefits of past investment decisions. This would likely provide useful lessons for future grid investment decisions.

7.167 For these reasons, the Authority is proposing that the guidelines require Transpower to develop a method and process for Transpower to review the application of the area-of-benefit charge for a high value investment if there has

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[212] Submissions on the options working paper: ASEC for IEGA (p.14), ASEC for Electra and KCE (p.6), Marlborough Lines (p.7), MEUG (p.2), New Zealand Steel (p.1), PowerNet (p.4), Trustpower (p.34), Unison (p.8), Westpower (p.5), Buller (p.3, p.5), Meridian (p.2), Nova (p.3), NZ Energy (p.4), TNT2 (p.2).

been a material change in circumstances, and adjusting the charge if necessary. The TPM would also be required to include a method and process for deciding when a material change in circumstances has occurred (which must include consultation with interested parties).

7.168 The reassessment process should address some concerns raised by submitters regarding "free riding" or "free loading".[213] The Authority is of the view that, to the extent that there would be such problems with the area-of-benefit charge, such problems would be much less than under the status quo, under which generators do not pay, and revenue is spread through the interconnection charge.

7.169 There is a risk that a review process could encourage participants to inefficiently avoid the charge, because it would give parties incentives to alter their behaviour to demonstrate that they would not benefit from the investment and so reduce future charges for themselves. However, the fact that the timing of future reviews would be uncertain should minimise the likelihood of such behaviour.

7.170 The Authority previously considered the option of requiring periodic reviews, such as every five or ten years. Relative to the 'material change' approach proposed above, periodic reviews would reduce incentives for parties to expend resources lobbying Transpower to convince it that a material change has occurred.

7.171 However, the Authority is concerned that periodic reviews could increase incentives for parties to inefficiently alter their grid use close to a review period to mimic a material change in circumstances and so reduce the future allocation of area-of-benefit charges to themselves. The uncertainty arising from the 'material change' requirement is likely to weaken those incentives. Moreover, the information contained in lobbying for recognition of a material change in circumstances is likely to be useful to Transpower in determining whether it should consult on whether a material change has occurred.

Charge to include allocation of maintenance and operating expenses

Discussion: allocation of maintenance and operating expenses

7.172 To ensure that area-of-benefit charges are cost-reflective and service-based, the charge should include an allocation for maintenance and operating expenses. Transaction costs aside, the ideal approach for allocating maintenance and operating costs would be an actual cost-based methodology. The Authority considers that Transpower is best placed to determine whether the benefit from introducing an actual cost-based methodology would exceed the cost of implementing and operating it. Accordingly, the Authority has included development of an actual cost-based methodology as an additional component of the Authority's TPM proposal. This methodology would apply to both connection assets and investments subject to the area-of-benefit charge.

7.173 In the absence of an actual cost-based allocation methodology, a method is needed to allocate maintenance and operating costs in relation to assets subject to the area-of-benefit charge that is at least broadly cost-reflective. This may

[213] For example, see the following submission on the TPM options working paper: Trustpower (Bushnell) (p.5).

involve the use of allocators that broadly reflect the drivers of maintenance and operating costs.

7.174 The Authority believes that calculating and allocating operational and maintenance costs on an actual cost basis would make the charge more cost-reflective, potentially improving the efficiency of the charge.

Modelling results for the proposed area-of-benefit charge

7.175 The Authority has modelled the area-of-benefit charge for a period representing the 2019 year using the SPD model on a forward-looking basis (called the forecast SPD approach). Given the uncertainty in demand growth, this is indicative of the period from 2019-2021. This approach has been adopted because the method is relatively well understood by the Authority and stakeholders and it was a reasonable option for calculating indicative charges. However, as discussed in paragraph 7.80, there are several other methods Transpower could propose to the Authority to implement the area-of-benefit charge. Appendix B provides details about the Authority's modelling of the area-of-benefit charge using the forecast SPD model.

7.176 Some examples of investments that are being modelled as being primarily for the benefit of load are:

(a) North Island grid upgrade (NIGU) project

(b) North Auckland and Northland NAaN project

(c) Lower South Island renewables project.

7.177 Some examples of investments that are being modelled as being for the benefit of both load and generation are:

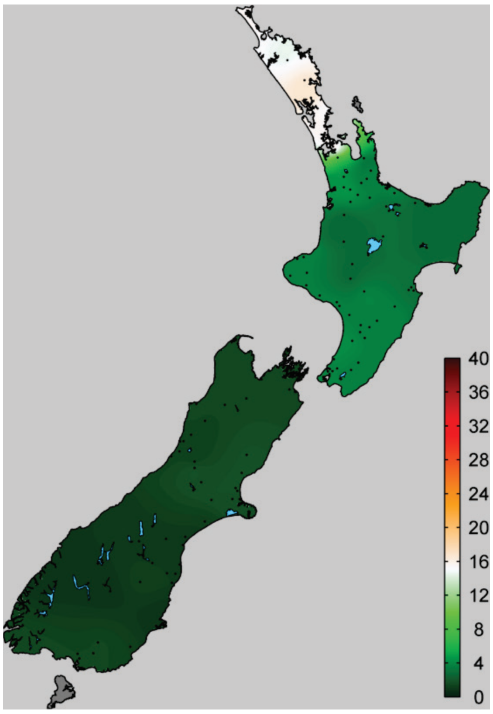
(a) Pole 2

(b) Pole 3

(c) Wairakei Ring.

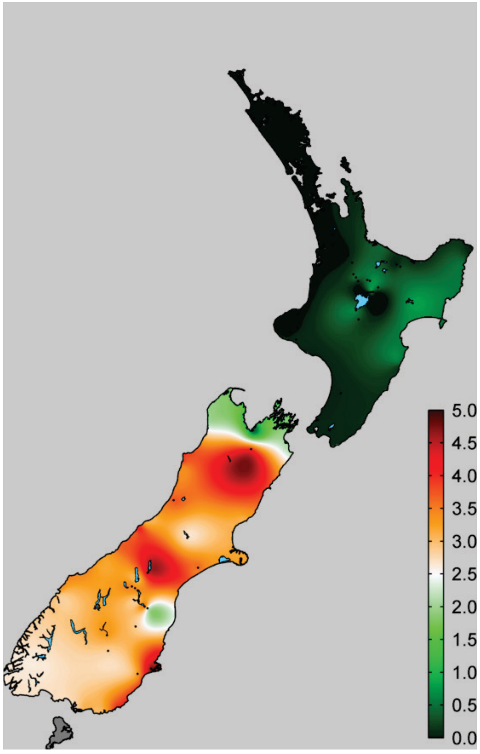
7.178 Figure 12 shows a heat map illustrating the incidence of the charge on distributors in fully variabilised terms ($/MWh) under the scenario modelled. Note that charges have been calculated on a DHC and not ODHC basis for historical assets and RC basis for new assets. The modelling can therefore be considered to represent an indication of the highest incidence of possible area-of-benefit charges. Area-of-benefit charges are greatest in the upper North Island because the proposed initial coverage of the area-of-benefit charge includes large investments where the main beneficiaries are upper North Island load.

Figure 12: Modelled incidence of area-of-benefit charge on distributors in fully variabilised terms ($/MWh)



7.179 Figure 13 shows the initial incidence of the proposed area-of-benefit charge for generation. Area-of-benefit charges are higher for South Island generation because they are major beneficiaries of Poles 2 and 3 of the HVDC.

Figure 13: Modelled incidence of area-of-benefit charge on generation in fully variabilised terms ($/MWh)



Main component 3: residual charge

Proposal

7.180 The proposed guidelines would require that the TPM include a residual charge to allocate costs that are not allocated through other TPM charges, or any lesser amount determined by Transpower (for example, to ensure that transmission remains competitive with an alternative, eg. mass solar).

7.181 The Authority is proposing that the residual charge would be a charge on load customers only, based on physical capacity. The TPM guidelines would require the TPM to specify whether physical capacity for each load customer is:

(a) the customer's transformer capacity in the 12 months prior to the publication of this paper

(b) the customer's line capacity in the 12 months prior to the publication of this paper

(c) the customer's gross anytime maximum demand in the 5 years prior to the publication of this paper.

7.182 If the gross anytime maximum demand measure is used, the guidelines would require that the TPM specify whether gross anytime maximum demand for a customer is—

(a) the customer's highest gross demand in the 5 year period

(b) the average of the customer's highest gross demands in each year

(c) the average of the customer's 5 highest gross demands in the five-year period

(d) another method for calculating gross anytime maximum demand.

7.183 To the extent practicable and to the extent that the transaction costs of doing so would not be prohibitive, gross anytime maximum demand must be anytime maximum demand, including electricity generated by generation connected to the customer's network, demand-side management and demand response.

7.184 The requirements in relation to practicability and transaction costs may mean that Transpower may choose include a threshold for a minimum size for the calculation of the level of these activities in periods used to calculate gross AMD.

7.185 To avoid the physical capacity measure becoming anomalous over time, Transpower would have the ability to review the time period in relation to which physical capacity is calculated after a period of time (in years), to be specified in the TPM, has elapsed, if there has been a material change in circumstances. Transpower would be able to substitute the relevant time period with another time period of the same duration that ends on the date that is the period of time (in years) specified in the TPM before the date of substitution.

Discussion

The residual charge is expected to reduce over time

7.186 The amount of revenue to be recovered with the residual charge ("residual revenue") equals Transpower's maximum allowable revenue (MAR) minus the revenue recovered from all of the other charges included in the TPM. Transpower could also develop the TPM to recover a lesser amount though the residual (for example, to ensure that transmission remains competitive with an alternative, eg. mass solar).

7.187 The following factors would affect the residual revenue to be recovered:

(a) The area-of-benefit charge would apply to all new investments except where assets are connection assets (subject to the phasing in of the simplified method), and to replacements and refurbishments. The residual revenue would therefore decline as replacements and refurbishments occur.

(b) The area-of-benefit charge is based on RC for all new assets, including replacements and refurbishments. Residual revenue would increase if RC values decrease, and vice versa, because RC determines the level of revenue gained from the area-of-benefit charge relative to revenue gained from the residual.[214]

(c) Optimisation of existing and new assets would reduce the asset values for the area-of-benefit charge, increasing the residual to be recovered with the residual charge.

7.188 Overall, the Authority's view is that (a) above is likely to outweigh (b) and (c), and so will drive a reduction in the residual charge over time.

7.189 In many industries RC declines over time due to advances in technology, but ever tighter safety and resource management requirements appear to have greatly increased the replacement cost for transmission assets. It is possible these resource management effects have peaked. In that case, technological advance would drive reductions in RC values. Also, a fast rate of adoption of alternatives to existing interconnected grid assets and rapid changes in the pattern of demand across the interconnected grid would result in significant optimisation, reducing ORC and ODHC. Under those scenarios, the residual charge could increase over time.

No peak-based charge

7.190 The residual charge would not be an explicit peak-based charge.

7.191 The Authority is of the view that a peak-based charge (such as the current interconnection charge), may be of benefit if other measures to promote efficient transmission investment are limited, and if transmission investment is expected in the short to medium term.

7.192 Provided it is allocated in accordance with expected benefits, the proposed area-of-benefit charge would avoid incentives for inefficient investment in the interconnected grid and inefficient investment by grid users, while having minimal impact on use in the short term of the interconnected grid and operation of the electricity industry.

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214 Transpower's MAR is not dependent on RC because MAR is calculated on DHC.

7.193 As discussed in chapter 5, in the Authority's view the nodal spot market in New Zealand produces a transport charge that provides reasonably efficient incentives for short term use of the interconnected grid and operation of the electricity industry. In addition, if needed, an LRMC charge could be adopted to provide an additional signal to promote efficient investment and efficient operation. Nodal pricing and an LRMC charge sit higher on the DME framework and address the same efficiency problems as a peak-based charge—ie, they would incentivise parties to reduce their use of congested assets, and so defer inefficient grid investment.

7.194 The Authority is of the view that nodal pricing, the area-of-benefit charge and an LRMC charge, if needed, in combination with the Commerce Commission's price-quality regulation and Transpower's demand response programme, are sufficient to promote efficient investment in the interconnected grid.

7.195 Retaining a peak-based residual charge in addition to the above would cause over-signalling, which would be inefficient.

7.196 Any charge based on capacity or maximum demand runs the risk that customers will perceive it as a peak charge, and undertake inefficient measures to avoid it. Two features of the charge would counter this. First, the provision for Transpower to review and substitute the time period in relation to which physical capacity is calculated means that the present value of any avoidance measure will be much diminished at any reasonable commercial discount rate. Second, in relation to gross anytime maximum demand only, the guidelines would require that the TPM provide for capacity to be adjusted for any distributed generation, demand-side management or demand response the customer has, to the extent that such an adjustment is practicable and does not involve prohibitive transaction costs.

Charge would apply to load only

7.197 The residual charge would apply to load only, rather than to load and generation customers.

7.198 The Authority is of the view that generation is more likely than load to alter its behaviour if the residual charge were applied to both. Thus applying the residual charge to generation is likely to result in more costly distortions to generator investment and operation decisions. For example, some submitters have argued that applying the charges to generation would create incentives for generators to inefficiently amend their wholesale offers in order to avoid charges.[215] The Authority is of the view that a very high proportion of a flat-rate residual charge on all generators, such as a MWh charge, is likely to be passed onto consumers in the form of higher wholesale electricity prices, which means load customers will end up effectively paying the charge anyway.

7.199 As the residual charge can be levied on load customers with minimal distortions, and transaction costs would be lower if the charge is applied only to load rather

[215] As raised by the following submitters on the options working paper: Nova (p.3), Contact (p.3), Meridian (p.23), Transpower (CEG report) (p.56).

than to both load and generation, the Authority is of the view that it is not efficient to apply the residual charge to generators.

7.200 The residual charge would be allocated to direct consumers and distributors on the same basis. This would reduce the incentive on large consumers on distribution networks to inefficiently connect directly to the grid, which was a concern many submitters raised about the residual charge option that was considered in the options working paper. It also addresses the concerns, raised by a large number of submitters, that having a different allocation method for distributors and direct consumers would result in disproportionately high charges to distributors, but without a corresponding efficiency rationale for this.[216]

Addressing dilution of price signals from pass through of residual charge

7.201 Some submitters were concerned the residual charge would be passed through to mass-market consumers through variable consumption charges, which would dilute price signals.[217] This issue is being addressed through the Authority's review of distribution pricing.

Modelling of residual charge

7.202 The Authority has modelled the capacity-based residual charge for the period representing the 2019 year. Given the uncertainty in demand growth, this is indicative of the period from 2019-2021. Refer figure 14 below.

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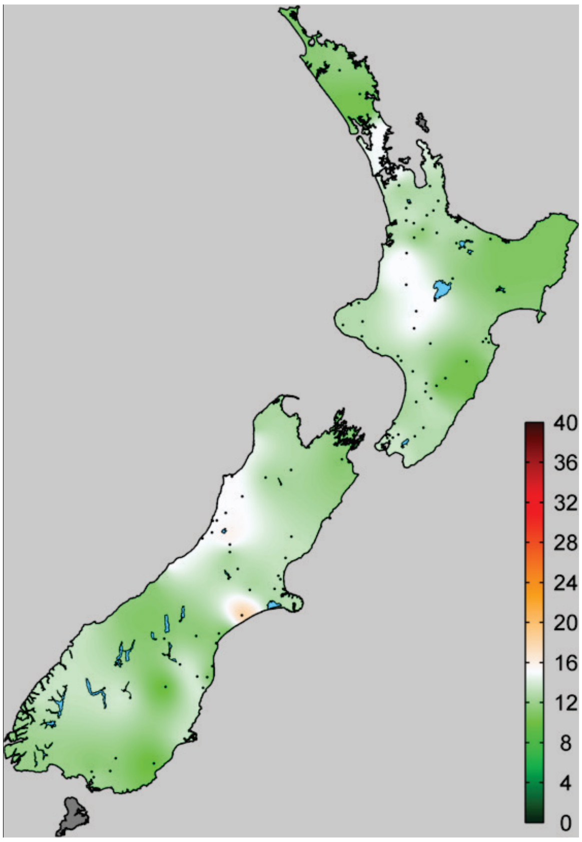
216 For example, in submissions on the options working paper: ASEC for Electra and KCE (p.12), ENA (p.12), Powernet (p.4), TLC (p.5-6), Top Energy (p.4), Unison (p.13), MRP (p.3-4), Contact (p.3-4), Powerco (p.2,7-8), Tai Tokerau Northland (p.4), Pioneer (p.2), TNT2 (p.4), KCE (p.1), IEGA (ASEC report) (p.11,15), Meridian (p.2), Genesis (Castalia report) (p.29), Transpower (p.4).

217 Marlborough Lines (p.10-11), ENA (p.11), Network Tasman (p.3), Orion (p.7), PwC (p.12), Top Energy (p.5), Top Energy Consumer Trust (p.2).

Figure 14: Incidence of residual charge on distributors in fully variabilised terms ($/MWh)



7.203 Figure 14 shows that capacity-based residual charges are highest (in fully variabilised terms) for distributors in the Ashburton area and Westland. The main reason for the higher charges in these areas is that they have relatively low offtake in energy terms, but high peak demand (ie, a low load factor).

Recovery of Transpower's overhead and unallocated operating expenses

Proposal

7.204 The Authority's preferred approach is that Transpower's overhead and unallocated operating expenses ("overheads") would be recovered from generation customers through the connection charge, and from load designated transmission customers through the residual charge.

7.205 The expenses would be required to be allocated on substantially the same basis, and with the same effect, as the current TPM.

Discussion

7.206 Transpower's overheads for owning and operating the transmission grid amounted to $198 million in the financial year 2015/16. Under the current TPM, Transpower's overheads are recovered from:

(a) generator customers, through the connection charge

(b) load customers, through the interconnection charge.

7.207 Overheads are in general "common costs". That is, they are incurred irrespective of the addition of a customer or service. Accordingly, overheads should be recovered in a manner that does not distort use of, or access to, the grid. However, simple approaches that make the level of overheads highly transparent and easy to understand may also bring efficiency gains by encouraging greater cost discipline.

7.208 The Authority is considering whether to retain essentially the current approach to recovering Transpower's overheads: continue to recover the allocation of overheads to generators through the connection charge, and to recover the allocation of overheads to load through the residual charge. The Authority calls this the "residual based approach".

7.209 However, the Authority is also considering whether Transpower's overheads should be recovered from transmission customers in proportion to each transmission customer's combined connection, area of benefit and residual charges. The charge would be levied by applying a percentage surcharge to all of those charges. The Authority calls this the "surcharge-based approach".

7.210 The rate of the surcharge would be calculated as the ratio of Transpower's overheads to the sum of all connection, area-of-benefit and residual charges. For example, the surcharge rate for 2015/16 would have been 28%.[218] That is, each customer's connection, area-of-benefit and residual charge would be multiplied by 1.28 to determine the final amount for each charge.

7.211 Neither approach to allocating overheads completely avoids distorting grid user behaviour.

7.212 For example, the residual-based approach allocates overheads among generators in proportion to the replacement cost of their connection assets.[219] Hence, if the annual capital cost of a proposed new connection asset was $1 million, the generator would be charged about $1.5 million.[220] The $500,000 wedge between incremental cost and the incremental charge reflects Transpower's existing costs, which it incurs regardless of whether the generator agrees to have the new connection asset or not. This wedge encourages generators to make inefficient choices about new connection assets.

7.213 However, the residual based approach would not distort load behaviour because load would pay for overheads in proportion to their residual charge, and the residual charge would be based on each customer's physical capacity prior to the date of the release of this paper, ie, prior to 17 May 2016. Hence, any changes in

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218 28%=100 x $198m/$719m, where $198 million is Transpower's overhead costs for 2015/16. Transpower's revenue requirement for 2015/16 is $917 million, and so deducting overheads from this figure gives the total revenue that would be raised in total from connection, area-of-benefit and residual charges in 2015/16.

219 There is also a pre-allocation of overhead expenses between generation and load which is based on the portion of maintenance costs allocated to "generation" connection assets compared to the maintenance costs of all alternative current (AC) assets. See clauses 21-24 of the current TPM. Transpower advised the Authority that, for the 2015/16 pricing year, $11,878,763 of total overhead costs of $197,983,000 was allocated to generators

220 This is calculated by dividing the total annual capital charge of "generation" connection assets by the total annual overhead allocation to generators - $18 million pa, divided by $11,878 million pa = $1.5 million.

connection or interconnected assets would not alter the transmission customer's residual charges, and therefore not alter their share of overheads.

7.214 In contrast, the surcharge-based approach would impose a wedge on the annual cost of new connection and area-of-benefit assets, for both load and generation customers. In 2015/16, this wedge would have equalled about 28%. Hence, the wedge is lower for generators in regard to connection services (compared to the 50% connection wedge they face under the residual based approach), but the wedge is much higher on new connection assets for load and on new 'area-of-benefit' assets for both load and generation (it was 0% in both cases under the residual based approach).

7.215 In effect, the surcharge-based approach broadens the base over which overheads are recovered, which could potentially limit the distortion that arises on generator connection decisions. Also, the surcharge-based approach makes the overheads charge highly transparent, potentially 'shining the spotlight' on Transpower's overheads, enhancing pressure on Transpower to reduce those costs wherever feasible.

7.216 On the other hand, as explained in paragraph 7.214, the surcharge-based approach imposes a substantial surcharge on connection charges (for load) and area-of-benefit charges (for both generation and load), significantly reducing the cost-reflectivity of those charges.[221] The effect is to charge customers more than their share of the full cost of the asset over its life for access to the asset. This could lead transmission customers to oppose a new investment even though the benefit that they derive from the asset exceeds its cost, therefore undermining the efficient incentives the Authority wants to promote. In contrast, the residual charge is designed to avoid this effect.

7.217 The above considerations mean it isn't clear cut at this stage whether the residual-based or surcharge-based approach would be the most efficient approach. The Authority would welcome submitters' views on the relative merits of these two options or variants to them.

7.218 The Authority's current preference is for the residual-based approach as:

(a) it is essentially the same as the current approach to allocating Transpower's overheads

(b) it is likely to be more efficient than the surcharge-based approach on the assumption that Transpower's overheads are already efficient

(c) transparency of Transpower's overheads can be achieved in other ways, for example by Transpower:

  (i) publishing its overheads as a percentage of its total revenue requirement (net of overhead)

  (ii) in transmission customer invoices, expressing each customer's overheads allocation as a percentage of that customer's total transmission charges (net of their overheads allocation).

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[221] As discussed in chapter 5 of this paper, cost-reflectivity is a fundamental principle for efficient transmission charges.

7.219 As Transpower's overheads are a large portion of its regulated revenue requirements, the approach to allocating overheads can have a noticeable impact on the transmission charges paid by some transmission customers. Under the surcharge-based approach, for example, transmission customers with a greater proportion of area-of-benefit charges relative to other customers would bear a higher share of overheads compared to what they would pay under a residual-based approach.

7.220 The indicative modelling of the Authority's TPM proposal is based on the residual approach.

Question 4: Do you prefer the residual-based approach or the surcharge-based approach or some variant of the two and why?

Charges for a new entrant

Proposal

7.221 If a new customer connects to the interconnected grid and Transpower takes the view that this is not a material change in circumstance, it is proposed that Transpower establish the area-of-benefit 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 area-of-benefit 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 each other customer's area-of-benefit and residual charges down so that:

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

(ii) the relativity between different customers' (excluding the new entrant) area-of-benefit charge and residual charge is maintained.

Discussion

7.222 If a new customer connects to the interconnected grid, charges have to be established for the new entrant.

7.223 The capacity-based residual charge approach is by definition impractical for new grid connected customers. For the same reason as for existing customers, it is important that the charge is not related to its physical capacity after it enters. Instead, it is proposed that Transpower develop a charge for new customers that is a proxy for, but not dependant on, its physical capacity after it enters. It might, for example, be related to the customer's total cost of operation at the site serviced by the customer's connection.

7.224 The Authority is of the 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 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.[222]

7.225 The Authority is aware that the charge faced by the customer is likely to be above incremental cost. As a result, there is the possibility that a potential new entrant that would be profitable at incremental cost may not be profitable at the charges calculated by Transpower under this proposal. However, the Authority is of the view that it would be a rare circumstance for the decision about a potential entrant to enter to turn on the difference between the charges Transpower determines and incremental cost.

7.226 There are a number of ways that Transpower could implement the proposal. The Authority is of the view that it would be for Transpower to determine the best method of achieving the proposal above in developing the TPM.

Main component 4: prudent discount policy

Proposal

7.227 The proposed guidelines require that the TPM include a prudent discount policy (**PDP**). The prudent discount policy would be on the same basis (and with the same effect) as the PDP in the current TPM, with the following additional features:

(a) a prudent discount would for the life of the relevant asset, unless a prudent discount for a shorter period is agreed between Transpower and the party receiving the prudent discount

(b) prudent discounts would be available to a load customer if it is privately beneficial for the load customer to build generation to disconnect from the grid, but is not efficient and would not be for the long-term benefit of consumers.

(c) a prudent discount would be available to a direct consumer if all of the following criteria are met:

- (i) the consumer's transmission charges are an amount that represents a material portion of the consumer's input costs and/or business profits
- (ii) there is a material risk that transmission charges would cause the consumer to close down its New Zealand plant (and so disconnect from the grid)
- (iii) the consumer has taken reasonable steps to remain viable as a going concern, including taking significant steps to eliminate unnecessary costs;

222 As discussed under the heading “Residual Charge” in this chapter, if Transpower uses a capacity basis for estimating benefits, there could be a difference between the new entrant’s actual capacity and its assessed capacity, which might create some inefficiency. The Authority is of the view that the inefficiency is likely to be minor.

(d) a prudent discount would be available to a distributor if the distributor can demonstrate that there is a material risk that both of the following are met:

(i) one of the distributor's customers would disconnect from the distributor's network

(ii) if the distributor's customer was a direct consumer in the same circumstance, the customer would be eligible to receive a prudent discount.

(e) a prudent discount would be available to a load customer if the load customer can establish that its transmission charges exceed the standalone costs of delivering electricity to the customer

(f) a prudent discount would be available to a distributor in respect of a load customer of the distributor if Transpower is satisfied that, if the load customer was a direct consumer, the prudent discount would be available on the basis specified in paragraph (e).

7.228 A prudent discount under paragraph 7.224(c) would be:

(a) linked to key factors that would have a material effect on the decision to disconnect from the grid (for example, the world price of the product or service produced by the customer)

(b) able to be reduced or suspended if the key factors relied on in granting the prudent discount change such that the prudent discount would not have been granted, or would not have been granted on the same basis.

7.229 Under the proposed guidelines, the TPM would be required to provide that a prudent discount must not result in a customer paying less than the incremental cost of supplying it with transmission services.

7.230 The proposed guidelines require that the TPM include methods and processes for assessing applications and calculating discounts in the circumstances described above.

Discussion

General rationale for granting prudent discounts

7.231 The economic rationale for granting prudent discounts is that the discounts avoid large inefficiencies in situations that can be characterised as ‘win-win’—ie, granting the discount avoids economic inefficiencies arising from the flat-rate nature of the residual charge, and avoids other transmission customers paying higher transmission charges.

7.232 For example, it can be better for all transmission customers that an applicant pays discounted transmission charges (exceeding incremental costs) if the alternative is that the applicant would disconnect from the grid and pay no transmission charges. The first scenario is a better outcome for all transmission customers because the applicant would be making some contribution toward common costs, whereas in the second scenario it makes no contribution to common costs, resulting in higher transmission charges for other transmission customers.[223]

7.233 In effect, the PDP is a practical alternative to applying efficient Ramsey pricing formula to the residual charge. By reducing the risk of inefficient disconnection from the grid, the Authority expects the proposed extensions to the PDP to achieve economic efficiency gains of an order of magnitude similar to what would be achieved with Ramsey pricing for these customers. This is because the proposed extensions avoid charges exceeding standalone costs and the prudent discounts while still ensuring that each party is paying at least the incremental cost of supplying transmission services to them.

7.234 Prudent discounts are market-like because they allow Transpower to reduce its charges to customers when that is considered to be necessary to meet the market costs of an alternative to transmission assets.

7.235 The Authority has considered using Ramsey pricing calculations to allocate the residual charge, as an alternative to extending the PDP to cover the risk of large load customers disconnecting from the transmission grid. The first step to applying Ramsey pricing is to estimate each customer's price elasticity of demand for electricity, which typically requires econometric estimation methods. These results are then used to estimate each customer's price elasticity of demand for transmission.[224] A high value for this calculation means the customer is sensitive to the rate of the residual charge and a low value means it is not. The second step is to set the rate of the residual charge for each load customer based on the inverse of the customer's price elasticity of demand for transmission from step 1, and then apply that rate to the charge the customer pays.[225]

7.236 This brief description shows that setting the residual charge in strict accordance with Ramsey pricing requirements would be very informationally-demanding, as robust estimates of demand and substitution elasticities would be required for

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223 As discussed in chapter 5, common costs are costs incurred by Transpower regardless of whether or not the transmission customer disconnected from the grid.

224 To see this mathematically, let E^c_e denote the customer's price elasticity of demand for electricity and let R^c denote the ratio of the customer's transmission charges to the customer's total electricity costs. Then the customer's price elasticity of demand for transmission, E^c_t, is given by the following formula: $E^c_t = R^c.E^c_e + (1-R^c).S^c$, where S^c is the price elasticity of substitution between transmission and other inputs used to produce electricity for customer c. E^c_t, E^c_e and S^c are all treated as positive numbers. If S^c is zero then $E^c_t = R^c.E^c_e$. In other words, customers have a high elasticity of demand for transmission if they have a high elasticity of electricity demand and a high ratio of transmission to electricity costs (ie, a high R). However, S^c is very unlikely to be zero. If S^c is relatively high, then an increase in R^c may actually reduce a customer's elasticity of demand for transmission. Hence, to apply Ramsey pricing it is important to have reasonably accurate estimates of E^c_e and S^c for all transmission customers.

225 To see this mathematically, let r^c denote the rate of the residual charge to be applied to customer c. As the residual charge is allocated to transmission customers based on their share of physical capacity, let K^c denote the customer's physical capacity. The residual charge paid by customer c is given by $r^c.K^c$. Ramsey pricing requires that r^c be set such r^c multiplied by each customer's elasticity of demand for transmission is the same number, λ say. That is, r^c is set such that $r^c. E^c_t = \lambda$ or equivalently $r^c = \lambda / E^c_t$. The number λ is set so that the total revenue collected is sufficient to fully fund the residual charge. That is, let RRR denote the total residual revenue requirement. Then $\lambda = RRR / \sum(r^c.K^c.E^c_t)$ where K^c is the total physical capacity of customer c, and the sum is across all customers.

every load customer or class of load customer, and those estimates are likely to change frequently.

7.237 The widely-held view of tax and regulatory policymakers around the world is that attempting to set prices in strict accordance with Ramsey pricing requirements:

(a) would incur very high administration costs and costs on participants to verify the parameters

(b) would very likely result in a wide range of rates that could be adopted for each load customer or class of load customer

(c) would result in very high prices on parties that have highly inelastic demand, which many parties would see as inappropriate.

7.238 As a result of these considerations the Authority has come to the view that a better approach is to extend the prudent discount policy to allow case-specific prudent discounts for load customers that can present a compelling case that they would otherwise inefficiently disconnect from the electricity system. It is likely that only a few load customers could mount a compelling case, as it would be necessary for applicants to establish that their transmission charges are a material portion of their input costs, that their business profits have been heavily affected by market conditions and that they have already taken reasonable steps to remain viable as a going concern (including taking significant steps to eliminate unnecessary costs).

Prudent discounts would apply for the life of the relevant asset unless otherwise agreed

7.239 Under the proposed guidelines, a prudent discount agreed between Transpower and the party receiving the prudent discount for the expected life of the asset to which the prudent discount relates, unless a shorter period is otherwise agreed between Transpower and the party receiving the prudent discount.

7.240 This would give a party certainty that the prudent discount that it obtains will be available for the full life of their investment, thus reducing unnecessary uncertainty and promoting efficient investment. It would also reduce the transaction costs involved in assessing applications for new prudent discounts at the end of the 15 year term.

7.241 Although the customer could qualify for access to the prudent discount for the life of the asset, whether they actually obtained a prudent discount in any period, and the extent of that discount, would depend on criteria such as the actual market conditions they face. For example, a customer’s charges could be restored if their international market conditions improved.

A prudent discount would be available to applicants for which it is privately beneficial to build generation to disconnect from the grid

7.242 Under the proposed guidelines, a prudent discount would be available in cases in which it is privately beneficial for a load customer to build generation to disconnect from the grid, but is not efficient and is not for the long-term benefit of consumers.

7.243 Some submitters viewed it as unlikely that industrial load customers would disconnect from the grid and self-supply. The Authority's view is that, in that case, prudent discounts would not be granted to applicants. However, the Authority is aware that the risk of disconnection because of the ability to self-supply is not just a risk in relation to industrial customers. Some distributors also are in a position where self-supply may be a commercially viable option, if not now, then in the future.

7.244 Other submitters expressed concern that prudent discounts might be granted in situations where an application lacked credibility.[226] Submitters were also concerned that it would be difficult to determine an appropriate weighted average cost of capital (WACC) for the annuity payment relating to a generation investment.[227] The Authority is of the view that these would be matters for Transpower to determine in developing the TPM. Under the proposed guidelines, the TPM would set criteria for assessing applications and calculating discounts under the PDP.

Prudent discount would be available if there is a material risk of a direct consumer closing down its New Zealand plant and disconnecting from the grid

7.245 A prudent discount would be available if there is a material risk that a direct consumer is paying transmission charges that would cause it to close down its New Zealand plant and disconnect from the grid. The customer's transmission charges must be a material portion of its input costs. The customer would have to demonstrate that it has taken reasonable steps to remain viable as a going concern, including taking significant steps to eliminate unnecessary costs. The customer would also have to demonstrate that its business profits have been heavily affected by market conditions.

7.246 The Authority is proposing that the value of any such prudent discount be linked to key factors that would have a material effect on the decision to disconnect, for example, the world price of the product or service produced by the direct consumer. The purpose of this linkage is to restore the applicant to contributing to a greater portion of Transpower's common costs when the applicant's circumstances improve materially to the point that the risk of disconnection is low.

7.247 Including these types of linkages would be market-like, as it would reflect the electricity supply contracts that some major industrial customers have secured from generators, which incorporate components that link to the world price of inputs or outputs of the customer.

7.248 An applicant for a prudent discount under this provision would need to establish that there is a material risk of the transmission charges causing the customer to disconnect from the grid. Transpower would develop a method and process for assessing this. A possible method would be for the applicant to provide independently audited information that verified that there was a material risk of disconnection.

7.249 The Authority recognises that this aspect of the PDP proposal would broaden Transpower's role and responsibilities with respect to the PDP, as it would

[226] Meridian submission on the October 2012 issues paper, (p. 50).

[227] Transpower (answers to questions) submission on the October 2012 issues paper, (p. 10).

require Transpower to assess whether transmission charges meant there was a material risk of closure of a load customer and disconnection from the grid. This issue also arises in relation to distributors with embedded customers seeking a PDP on a similar basis, discussed below.

7.250 Accordingly, the Authority requests submitter feedback on whether, if the PDP proposal is implemented:

(a) Transpower should make decisions around this aspect of the PDP proposal, or

(b) Transpower should be restricted to assessing and recommending on the applications, and the Authority or some other party would be the more logical and appropriate party to make the final decisions.

Extension of prudent discounts to distributors with embedded consumers in a similar circumstance as above

7.251 The above extension to the PDP creates incentives for embedded consumers to inefficiently disconnect from distribution networks and connect to the national grid so that they can access the PDP if their commercial viability may be at risk in the future.

7.252 To avoid creating these incentives, a prudent discount would be available to a distributor if the distributor can demonstrate that there is a material risk that transmission charges would cause one of the distributor's customers to disconnect from the distributor's network. The distributor would have to establish that, if the distributor's customer was a direct consumer in the same circumstance that a transmission load customer would be eligible for a discount under the "inefficient disconnection" provisions, the distributor's customer would be eligible to receive a prudent discount.

A prudent discount would be available to load customers that can establish their transmission charges exceed the standalone costs of delivering electricity to it

7.253 As discussed in chapter 5, it is inefficient to set a customer’s transmission charges greater than the standalone costs of delivering electricity to it. Transmission customers facing such high charges face strong incentives to disconnect from the national grid and build their own transmission assets or transmission alternatives. This outcome would be inefficient as it increases the total costs of the electricity system.

7.254 The cost of delivering electricity to a customer could exceed standalone cost for several reasons:

(a) there are practical limitations and trade-offs in designing the area-of-benefit and residual charges

(b) the Commerce Commission’s approach to setting Transpower’s maximum allowable revenue does not require Transpower to write down the value of under-utilised and unused assets. The cost of these stranded assets would be recovered by the residual charge

(c) similarly, the Commission can approve uneconomic grid investments to satisfy grid reliability standards. The proposals in this paper would mean that the net economic losses from these investments would be recovered through the area-of-benefit charge if the value of the asset is not later optimised down.

7.255 As for the other proposed extensions to the PDP, the proposed guidelines would require the TPM to include a method for determining when a standalone cost was exceeded.

7.256 The TPM would also provide that a prudent discount will be available to a distributor in respect of a load customer of the distributor if Transpower is satisfied that, if the load customer was a direct consumer, the prudent discount would be available on the basis that charges exceed the standalone cost of delivering electricity to the load customer.

Modelling of proposed additional features of the PDP

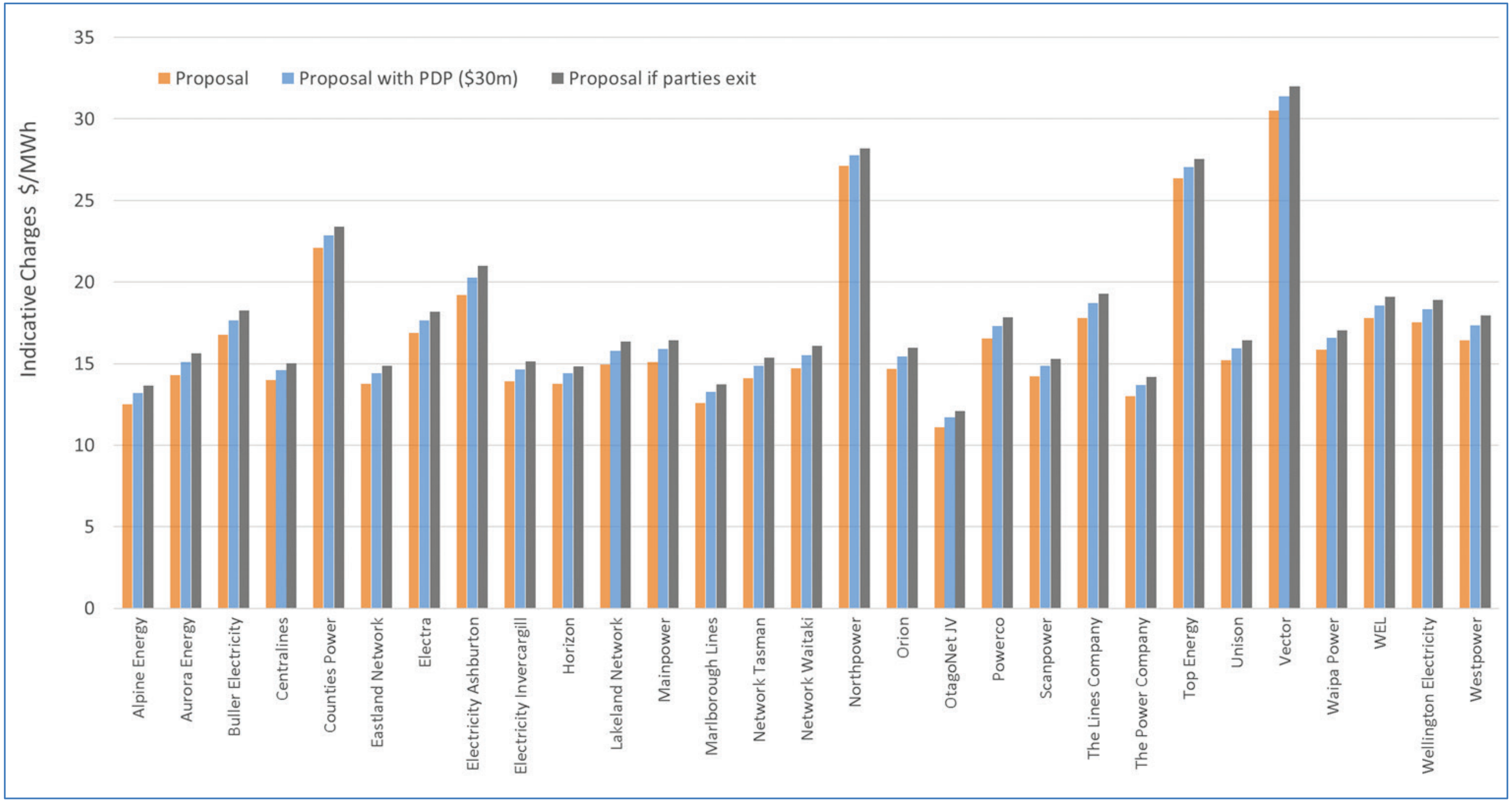
7.257 The bespoke nature of prudent discounts means it is not possible for the Authority to undertake general modelling of the impact of the proposed additional features of the PDP.

7.258 However, the Authority recognises that an early indication of the potential magnitude of discounts may be important for some load customers currently considering disconnecting from the grid.

7.259 For similar reasons, the Authority appreciates that substantive discounts could materially alter the aggregate proportion of the residual charge that would be charged to load customers.

7.260 The Authority has therefore modelled the effect of a hypothetical example of a PDP that reduces a load customer's charges by $30 million per annum to illustrate the implications for other customers' charges. This is shown in Figure 15. Figure 15 shows that the effect of a PDP is to increase charges slightly for load customers, as the costs of the PDP would be recovered through the residual charge. The modelling indicates a $30m PDP would result in a 4.3% increase in customer’s charges in $/MWh terms. Figure 15 also shows that if the customer disconnected because they did not receive a PDP, parties’ charges would increase by 7.2%, assuming that exit would require reallocation of $50m in charges.

Figure 15: Charges to distributors in $/MWh showing the impact of $30m PDP and charges if parties otherwise exit



Additional component 1: staged commissioning

Proposal

7.261 As stated above, the proposed TPM guidelines provide for Transpower to include additional components in the TPM if Transpower considers that doing so would be practicable and consistent with the matters in clause 12.89 of the Code.

7.262 The proposed guidelines require Transpower to consider including in the TPM, as an additional component, an amendment to the connection charge to clarify that, if assets are commissioned such that they meet the definition of "connection assets", they are charged for as connection assets, including if they will ultimately be configured such that they would no longer meet the definition of "connection assets".

Discussion

7.263 The proposal would remove ambiguity in relation to staged commissioning. Charges would be based on whether an asset met the physical definition of a connection asset when charges were being calculated, and not on the ultimate configuration or purpose of an asset.

7.264 The experience from staged commissioning under the NAaN project suggests that the charging treatment under staged commissioning could be made clearer. Removing any ambiguity would reduce uncertainty and therefore mean that parties have incentives to consider the cost implications of staged commissioning as part of their assessment of whether a transmission investment proposal provided net benefits. This would help promote efficient investment.

7.265 The proposal should reduce uncertainty over the boundary between connection and non-connection assets, and so reduce unnecessary and inefficient disputes. It is being proposed as an additional component because there is no immediate circumstance in which the issue looks likely to arise, and the Authority's decision and the High Court ruling on the NAaN exemption applications provide guidance in the interim. Hence, it is not as urgent or important as other aspects of the proposed TPM.

7.266 The proposal could create incentives for participants to avoid staged commissioning. However, the incentives to do so would be weaker than under the status quo. Under the Authority's TPM proposals presented in this chapter, it is very likely that the costs of a redesign of the asset (to avoid the asset meeting the connection definition) would be met to a significant degree by the potential connection customer under the proposed options. This is because it is likely that the costs of the asset, once fully commissioned, would be met through the area-of-benefit charge, and it is likely that the customer receiving temporary connection services would also be subject to this charge.

Additional component 2: charging for assets when their classification changes due to other investments

Proposal

7.267 The proposed guidelines provide for Transpower to consider including in the TPM, as an additional component, a method to ensure that charges that apply to assets that provide connection services, by connecting a customer to the grid, are not affected by an investment (by a person other than Transpower) that connects connection assets to assets owned by Transpower.

Discussion

7.268 Waipa Networks has recently constructed a new line between the Te Awamutu and Hangatiki substations, creating a loop with assets that have been classified as connection assets and therefore subject to connection charges. This has raised the issue of how to charge for connection assets when they are subsequently linked to form a loop, because "looped assets" potentially become interconnection assets.

7.269 The new line and associated works (switchgear) is being constructed under a customer investment contract (CIC) and the costs are recovered under that CIC. However, when the new line is commissioned, the substations and related assets become part of a loop. As a consequence it appears that some of Transpower's assets (for example, the Karapiro-Te Awamutu line) may become interconnection assets as defined in the TPM, even though the new line that completes the loop is owned and operated by a grid provider other than Transpower (ie, by Waipa Networks) and the new lines will not be a grid asset in respect of which the TPM allocates charges.

7.270 The relevant definitions in the TPM (in particular, connection link, connection node, interconnection link and interconnection node) rely on the physical and electrical configuration of assets, not ownership, except in the definition of "grid asset". The definition of grid assets identifies the specific assets in respect of which charges in the TPM must be calculated.

7.271 As a result, under the current TPM, some assets previously categorised as connection assets appear likely to become interconnection assets, and their costs would be recovered through the interconnection charge.

7.272 Under a TPM that reflected the proposed guidelines, it is likely that the cost of those assets would be recovered through the residual charge, at least until they were replaced or refurbished, in which case they would be recovered through the area-of-benefit charge.

7.273 The Authority considers that this situation does not promote efficient investment to the extent that the costs of connection and interconnection assets are recovered differently. If the charges that a customer faces when the assets are classified as interconnection assets are less than they would face when the assets were classified as connection assets, it provides an incentive for the customer to have them classified as interconnection assets, and so makes the construction of new lines more economically viable for the party constructing the relevant line.

7.274 The Authority therefore considers the guidelines should require Transpower to provide for connection assets to continue to be categorised as such when the assets are connected by a new line, and the assets continue to provide connection services through connecting customers to the grid.

Additional component 3: charging for operating and maintenance on an actual cost basis

Proposal

7.275 The proposed guidelines provide for Transpower to consider including in the TPM, as an additional component, a method of allocating operational and maintenance costs for a connection asset or an asset to be recovered through the area-of-benefit charge to the parties that pay charges in relation to that asset.

Discussion

7.276 The Authority is of the view that the proposal would better align the connection and area-of-benefit charges with the cost-reflectiveness principle discussed in chapter 5, and therefore lead transmission customers to make more efficient investment and operational decisions over time. Also as discussed in chapter 5, better cost-reflectiveness would promote scrutiny of operating and maintenance costs, which could lead to lower costs overall over time.

7.277 The Authority considers this is a lower priority issue because maintenance costs are generally a small component of the charges for an asset.

7.278 As stated in chapter 2, operating and maintenance costs are currently somewhat spread across connection customers through the use of broad cost allocators that reflect the average cost of operating and maintaining connection assets, rather than based on actual operating and maintenance costs in relation to an asset.

7.279 One benefit of retaining broad cost allocators is that it is a lower cost method of determining charges. However, the disadvantage of broad cost allocators is that they mask the differences in the actual costs of operating and maintaining different assets. Determining charges according to actual operating and maintenance costs would make the costs more transparent, giving customers the ability to test with Transpower whether they are reasonable. This would help put downward pressure on operating and maintenance costs, and contribute to lower costs overall over time.

7.280 There is a risk that this could lead to some customer resistance to maintenance that would extend the life of an asset. However, this seems much less likely than under the current TPM, unless deferring maintenance is in fact optimal. This is because the customers who would bear the maintenance charge would also have to pay the cost of the early replacement of the asset under the connection or area-of-benefit charge.

7.281 In proposing this change, the Authority notes that Transpower considers, aside from an issue regarding line maintenance,[228] that the current allocation method is fit for purpose, at least in relation to the connection charge. The Authority considers, however, that the proposed change would enhance the incentive mechanisms under the Commerce Commission's regime in providing pressure for lower maintenance and operating costs over time.

7.282 Some submitters have raised concerns that Transpower's customers do not have the ability to scrutinise Transpower's maintenance practices.[229] The Authority disagrees. Making Transpower's operating and maintenance costs more transparent will give Transpower's customers the ability to scrutinise the costs and require Transpower to justify why they are reasonable. Further, distributors have similar businesses to Transpower, albeit operating lower voltage assets, so they are in a strong position to scrutinise Transpower's operating and maintenance practices.

7.283 If maintenance charges are based on actual cost, parties may be incentivised to seek refurbishments or replacements earlier than is efficient to limit the maintenance charges they would face. To address this potential issue, the Authority proposes that, following replacement or refurbishment, Transpower would continue to charge the cost of the old asset until that asset is fully depreciated. The Authority also proposes that charges for the capital cost of an asset cease once it is fully depreciated and the full capital costs in respect of the asset have been recovered. This would provide a further efficient incentive on Transpower's customers to oppose unnecessary replacements or refurbishments.

7.284 The Authority notes that, during the course of consultation on this review, some parties submitted that maintenance costs are negatively correlated to DHC as maintenance charges increase as an asset depreciates in value.[230] This would suggest that DHC or an asset's value would not be suitable allocators for maintenance costs.

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[228] Transpower considered allocation of maintenance costs in its operational review of the TPM. Transpower initially proposed to address an unintended divergence between Transpower's costs and line maintenance charges (Transpower proposal to the Authority to amend the Electricity Industry Participation Code, TPM Operational Review: Line Maintenance Recovery Rates, 13 February 2015, p.1). According to Transpower the divergence was caused by a change in the population of poles and towers due to Transpower asset transfers to connection customers. The Authority returned the proposal to Transpower and requested that it consider resubmitting a revised application that proposed moving to an actual cost-based methodology for maintenance charges (letter from the Authority to Transpower dated 14 April 2015, available on the Authority's website). Transpower's response was to withdraw its application in relation to line maintenance. Transpower informed the Authority that a Code change was no longer required at that point as the line maintenance problem could be addressed without a change to the Code (letter from Transpower to the Authority dated 8 May 2015, available on the Authority's website).

[229] For example, ENA (para 27) submission to the TPM connection charges working paper.

[230] Genesis (p.3) and Counties Power (p.2) submissions to the TPM connection charges working paper.

Additional component 4: LRMC charge

Proposal

7.285 The proposed guidelines provide for Transpower to consider the introduction of an LRMC charge, as one of the additional components, if that would be practicable and consistent with the requirements of clause 12.89 of the Code and be likely to yield net benefits.

7.286 The guidelines would require that the charge:

(a) is designed to promote the efficient use of the interconnected grid so as to efficiently defer investment

(b) complements or augments, but does not duplicate, the price signals provided by nodal pricing and other charges under the TPM.

7.287 If an LRMC charge was developed, the proposed guidelines would require that the TPM specify that the purpose of the LRMC charge is to promote a change in behaviour in use of the interconnected grid to efficiently defer investment, after taking account of nodal prices and other transmission charges.

7.288 Transpower would only be permitted to include an LRMC charge in the TPM if a price signal over and above the price signal provided by nodal pricing (or that could be provided by nodal pricing with direct refinements to the nodal pricing system), and other transmission charges, is necessary to promote efficient investment in, and use of, the interconnected grid.

Discussion

An LRMC charge would restrict grid use when that is efficient

7.289 The LRMC charge would be a market-like charge that would signal, over and above nodal pricing, the value of reducing use of some interconnected grid circuits in order to defer future transmission investment.

7.290 As discussed in chapter 5 under the heading “efficient pricing for interconnected grid services”, the nodal spot market produces a transport charge that is low when there is spare capacity on an interconnected grid circuit, and high when the circuit’s constraints bind. As demand increases, nodal prices rise to ensure that use of the circuit is limited to the circuit’s capacity. Eventually, the nodal price rises sufficiently to justify a new investment that eases the circuit’s constraint and reduces the nodal price. As several submitters noted,[231] under these conditions nodal prices signal the SRMC of congestion and so provide an efficient signal to defer future transmission investment until it is justified.

7.291 However, there may be circumstances in which this does not occur.

7.292 First, nodal prices may not accurately reflect the SRMC of using the interconnected grid. Alternatively a new investment may be triggered by circumstances other than circuit constraints binding. For example, increasing

[231] The following submissions on the options working paper: ENA (p.11, Transpower (CEG) (p.22), Powerco (p. 3).

use of a circuit may trigger a new investment to ensure that reliability standards are maintained.

7.293 As discussed in chapter 5, there are a number of circumstances in which nodal prices will not accurately reflect the SRMC of using the interconnected grid. In addition, even if nodal prices efficiently signal the cost of using the interconnected grid, consumers may not receive those price signals.

7.294 Moreover, consumers may not be well-placed to anticipate future nodal prices. When electricity consumers are deciding on an investment that uses or substitutes for transmission services (eg, distributed generation or home insulation), they would need to anticipate and factor in what the nodal prices will be over the life of the asset in order to make efficient investment decisions. It is reasonable to expect major consumers of transmission services—eg, generators and large industrial consumers—to rationally anticipate future changes in the price of transmission services. However, smaller consumers may not.

7.295 To address situations where nodal prices may be insufficient to signal the current or future costs of using the interconnected grid, it is proposed to allow Transpower to introduce an LRMC charge to supplement nodal prices.

7.296 The current stage of the transmission investment cycle means a relatively low level of investment is anticipated in the near future. Therefore, there may be limited benefits from implementing an LRMC charge component in the near term. However, the Authority considers that providing for an LRMC charge in the guidelines would nevertheless promote the Authority's statutory objective. Doing so would provide flexibility, by allowing Transpower to propose an LRMC charge if the transmission investment situation meant that implementing such a charge would promote the long-term benefit of consumers.

Charge would potentially apply to all assets

7.297 The LRMC charge would supplement nodal prices. It could therefore potentially apply to every node of the interconnected grid.

Transpower must take nodal pricing and other transmission charges into account

7.298 Transpower would be required to take into account the signal provided by nodal pricing and other transmission charges (area-of-benefit charges, connection charges, etc) when implementing the LRMC charge. Transpower would need to demonstrate that a signal over and above the signal provided by nodal pricing (or that could be provided by nodal pricing with direct refinements to the spot electricity market) and other charges was necessary to promote efficient use of, and investment in, the interconnected grid.

Calculation basis

7.299 If an LRMC charge was developed, the proposed guidelines would require that the TPM specify that the purpose of the LRMC charge is to promote a change in behaviour in use of the interconnected grid to efficiently defer investment, after taking account of nodal prices and other transmission charges.[232]

7.300 The calculation basis for the LRMC charge would be required to

(a) be designed to promote the efficient use of Transpower's grid assets that are not connection assets, so as to efficiently defer investment

(b) complement or augment, but not duplicate, the price signals provided by nodal pricing and other charges under the TPM.

7.301 The exact nature of the LRMC charge could vary, however, because to achieve its objective it would have to take account of the circumstances in which it was to be applied.

7.302 In theory, if end users of transmission services face nodal prices, and anticipate and react to them rationally, a short-run marginal opportunity cost (SRMOC) price of the kind discussed in chapter 5 should be sufficient to efficiently defer investment where nodal prices on their own are not sufficient to do so.

7.303 In practice, as discussed above, there will be situations when end users of transmission services do not efficiently anticipate future transmission prices in their current decision-making. In that case, it may be necessary for a different signal to be introduced to promote efficient use of the interconnected grid. For example, if small users of transmission services are not sufficiently forward looking in practice, then it may be desirable to have a forward-looking price signal, such as a signal equal to marginal incremental cost (MIC), to encourage them to behave as they would if they were forward looking.

7.304 Because the exact nature of the charge is situation specific, Transpower is best placed to determine the most efficient basis for calculating and applying the LRMC charge. If Transpower proposes a SRMOC charge, it would be required to identify why this was superior to simply relying on normal nodal prices, and why any deficiencies with nodal pricing are unable or unlikely to be addressed through direct refinements to the spot electricity market. If it proposes any other form of LRMC charge, it would be required to identify the circumstances that justified it, and why neither nodal prices nor a SRMOC charge was sufficient to promote efficient use of the interconnected grid.

LRMC is a charge for use of existing assets

7.305 The objective of the LRMC charge is to efficiently defer new investment. It does so by applying an additional charge for the use of existing assets to limit use of those assets, where additional use of those assets would lead to inefficiently early investment in new assets.

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[232] This is in contrast to the other charges proposed that are intended to recover revenue in relation to costs already incurred, ie, the connection charge, area-of-benefit charge, and residual charge. These charges need to be applied in a way that avoids promoting inefficient changes to use of the grid, eg, by applying these charges on a capacity basis. Note too that the LRMC charge would still allocate recoverable costs, but would provide a price signal as it does this (as is the case with the current interconnection charge).

The residual charge would reduce with an LRMC charge

7.306 The LRMC charge would reduce the costs that are allocated through the residual charge. This would reduce the economic distortions arising from the residual charge.

Additional component 5: kvar charge

Proposal

7.307 Under the proposed guidelines, Transpower would be required to consider the introduction of a kvar charge, as one of the additional components.

7.308 If Transpower included a kvar charge in the TPM, Transpower would be required to determine when the kvar charge would apply, and in what regions.

Discussion

7.309 As set out in chapter 6, power factors are currently tending towards unity, so there is little immediate benefit in introducing a kvar charge. However, the Authority considers that it would promote the Authority's statutory objective for the guidelines to provide for the introduction of a kvar charge if there are net benefits from having it in the future. This would give Transpower the option of proposing a kvar charge at some point in the future, if power factors deteriorate.

7.310 A kvar charge may provide a more efficient means of maintaining power factors than enforcing the power factor requirements in the Connection Code.

7.311 The Authority is of the view that Transpower is best placed to determine the details of any proposed kvar charge.

7.312 Distributors and direct consumers could choose to respond to the kvar charge by installing reactive support equipment, and distributors could also apply a kvar charge to their customers, which some have done.

7.313 Some submitters expressed the view that improving appliance standards would be likely to provide a more efficient response than kvar price signals. The Authority does not determine appliance standards, although it can influence such standards through its policies, such as the introduction of a kvar charge, which would provide incentives for parties subject to the charge to influence the standards. In any case, except for large consumers, it is likely to be more efficient to deal with reactive load through investment at the transmission or distribution level, than at the end consumer level.

7.314 The decommissioning of the Otahuhu B and Southdown power stations may increase the need for upper North Island *dynamic* reactive investment. However, because such equipment supports the importing of power into a region, it is proposed that the cost of this investment would be recovered on the same basis as the cost of other transmission investment that is not directed at addressing an externality, ie, through the area-of-benefit charge.

Additional change 1: Loss and constraint excess

Introduction: why does this paper discuss amendments in relation to LCE?

7.315 The Authority has included the LCE proposal in the TPM review because LCE is a market-based source of revenue for meeting Transpower's revenue requirements, and so that revenue source is most preferred under the DME framework. In addition, since the Authority is proposing changes to the TPM it is important that the combination of the LCE allocation and the charges under the Authority's TPM proposal are efficient.

7.316 As stated in chapter 2, LCE payments do not reduce the amount of transmission costs recovered under the TPM, but LCE payments offset transmission customers' individual transmission charges. This means that the incentives for customers are the same as if LCE payments did reduce the amount of transmission costs recovered under the TPM.

Proposal

7.317 The Authority proposes that the Code be amended to:

(a) include a formula that determines the proportion of LCE to be allocated to connection and area-of-benefit assets, and how LCE is to be allocated among those assets

(b) for LCE allocated to a connection or area-of-benefit asset under (a), require Transpower to allocate the LCE to the customers that pay charges in relation to that asset, based on the proportion of charges for that asset that each customer must pay under the TPM

(c) require that any remaining LCE be allocated to customers that pay the residual charge, such that each customer is credited LCE based on the proportion of the residual charge that the customer must pay under the TPM

(d) specify that the allocation method in the Code is deemed to be Transpower's "prevailing methodology" under the Benchmark Agreement.

7.318 Because the allocation method in the Code would be Transpower's "prevailing methodology" under the Benchmark Agreement, no amendments to the Benchmark Agreement would be required.

7.319 Transpower would continue to issue credit notes for LCE under the Benchmark Agreement.

Discussion

7.320 The proposal is a market-based approach. That is because LCE is generated through the operation of the wholesale market for electricity and LCE payments would be credited to Transpower's customers in proportion to the LCE attributable to the assets that provide them with services.

7.321 The proposal is similar to the proposal in the options working paper. The differences are that:

(a) the options working paper did not propose to allocate LCE to specific assets that are subject to the area-of-benefit charge [233]

(b) the options working paper proposed that remaining LCE would be "credited in bulk against Transpower's remaining recoverable revenue". In the new proposal, the remaining LCE would be credited to customers that pay the residual charge.

7.322 Several submissions on the LCE working paper raised concerns about distortions to behaviour if LCE was allocated to specific assets.[234] However, those submissions were originally made in the context of an SPD-based proposal, in which there was potential for small changes to behaviour to lead to material changes in transmission charges because of the design of that charge. There is a much lower risk of this problem with the charges proposed in this chapter, as the charges do not have the same direct relationship with outcomes of the wholesale market.

7.323 Some submitters were concerned that the proposal would result in undesirable volatility. However, allocating LCE to participants who pay for specific assets would not increase the volatility of charges those customers face. As is the case under the status quo, customers will receive a credit note against transmission charges.

7.324 The LCE working paper raised the possibility of extending the averaging period over which LCE was allocated (eg, annually rather than monthly) to limit any distortions to nodal prices, and therefore behaviour, caused in relation to allocation of LCE.[235] The Authority has decided not to extend the averaging period. Under the status quo, South Island generators that pay HVDC charges receive LCE attributed to the HVDC. If the Authority's proposed approach to the allocation of LCE gave rise to a risk of distortions to nodal prices sufficient to extend the averaging period, this would also be the case under the status quo in relation to the HVDC, but there is no evidence of such a problem.

7.325 The Authority notes that, in limited circumstances, LCE received by a party in relation to an asset may exceed the party's charges for that asset, for example, if an asset is severely congested. However, it is likely that, over the life of an asset, LCE received would be substantially less than charges paid. That is because, for most of the life of the asset, the LCE would be loss rentals, which are relatively small, rather than constraint rentals, which can be large. Further, because of factors such as economies-of-scale and building to reliability standards, LCE for an asset will be less than the revenue requirements for the asset.

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[233] In making this change, the Authority accepts the submission by ASEC that there is no principled reason for a difference in treatment between different assets, eg connection assets and area-of-benefit assets, and that different treatment might give rise to inefficient preference for some assets over others (see submission on the options working paper: ASEC LCE (p.1-2)).

[234] For example, the following submissions on the LCE working paper: ASEC (p.6), Genesis (p.4), Powerco (p.2), Transpower (p.1)

[235] Para 7.16, p.22, and para 8.25, p.27.

Additional change 2: power factor of 0.95 lagging

Proposal

7.326 The Authority proposes that the required power factor be relaxed to 0.95 lagging for all regions.

Discussion

7.327 The Connection Code incorporated by reference in the Electricity Industry Participation Code 2010 (Code) currently provides for a power factor of 1.0 for some regions and 0.95 lagging for other regions. Transmission customers must comply with the Connection Code under their transmission agreements with Transpower.[236] There is widespread non-compliance with these requirements.

7.328 Making the proposed change would reduce uncertainty by clarifying to transmission customers the level of the power factor that is acceptable. Further, it would provide a power factor level that Transpower could use as an indicator for when it may be appropriate to apply a kvar charge to a region. That is, if power factor levels dropped below the 0.95 requirement in the Connection Code, this would indicate to Transpower that a kvar charge may be appropriate and could trigger an investigation of whether the benefits of imposing it exceed the administrative cost of doing so.

7.329 The Code specifies a process that must be followed in amending the Connection Code. The Authority would follow this process.

7.330 Some submitters have suggested that minimum power factor requirements would not be necessary if the TPM includes a kvar charge. However, the Connection Code already contains minimum power factor requirements. While one option would be to have no minimum power factor requirements, including such a requirement reduces uncertainty. In addition, the proposed TPM guidelines provide for a kvar charge as an additional component, so it would be up to Transpower to determine whether to propose that a kvar charge be included in the TPM.

Overview of modelling results for the Authority's proposal

7.331 The Authority has modelled its TPM proposal for a hypothetical scenario representing the 2019 year. Given the uncertainty in demand growth, this is indicative of the period from 2019-2021.

7.332 The following charges have been modelled:

(a) area-of-benefit

(b) residual.

7.333 The LRMC charge and kvar charge have not been modelled. An illustrative example of the changes to the PDP is provided below. Where included,

[236] Clause 12.17 of the Code provides that "Transpower and designated transmission customers must comply with the Connection Code under default transmission agreements that apply under clauses 12.10 and 12.13". The Connection Code is Schedule 8 to the Benchmark Agreement.

indicative estimates have been provided for connection charges and LCE. No caps or transitions have been modelled.

7.334 The Authority's modelling is indicative only. Actual charges are likely to differ depending on how Transpower designs and implements the TPM.

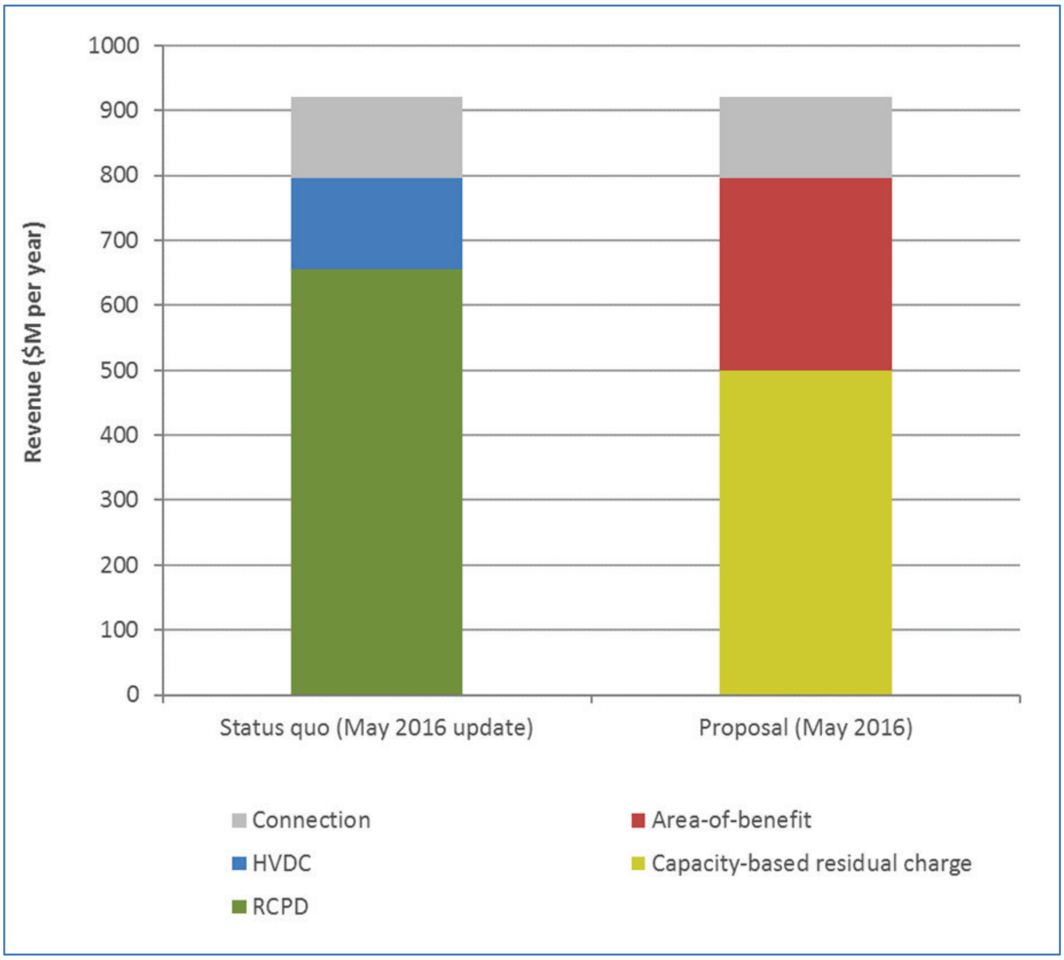
7.335 The modelling indicates that the area-of-benefit charge recovers about $296m per year, of which 79% is from load, and $500m per year through the residual charge (of which about 2% is charged to generation for their offtake).

7.336 It is important to note that the Authority proposes that assets in the area-of-benefit charge are subject to possible optimisation, so actual revenue recovered from the area-of-benefit charge is likely to be lower than shown, although the magnitude of this would depend on the degree of optimisation applied. This would also affect the revenue recovered from different customer groups relative to that shown.

7.337 Figure 16 provides a breakdown of the revenue recovered from the charges proposed as main components under the Authority's proposal compared with the status quo. Transpower's forecast revenue for 2015/16 is close to $917 million. The amount shown for connection is an indicative estimate that was not otherwise modelled for the paper.

7.338 Figure 16 shows that under the Authority's proposal, the area-of-benefit charge would recover initially about 32% of Transpower's forecast revenue, with the remainder recovered through the residual charge and connection charge. It is important to note that over time this proportion would be likely to change as more investments would become subject to the area-of-benefit charge.

Figure 16: Transpower's regulated revenue modelled as being recovered from different charges under Authority's proposal versus status quo and previous options



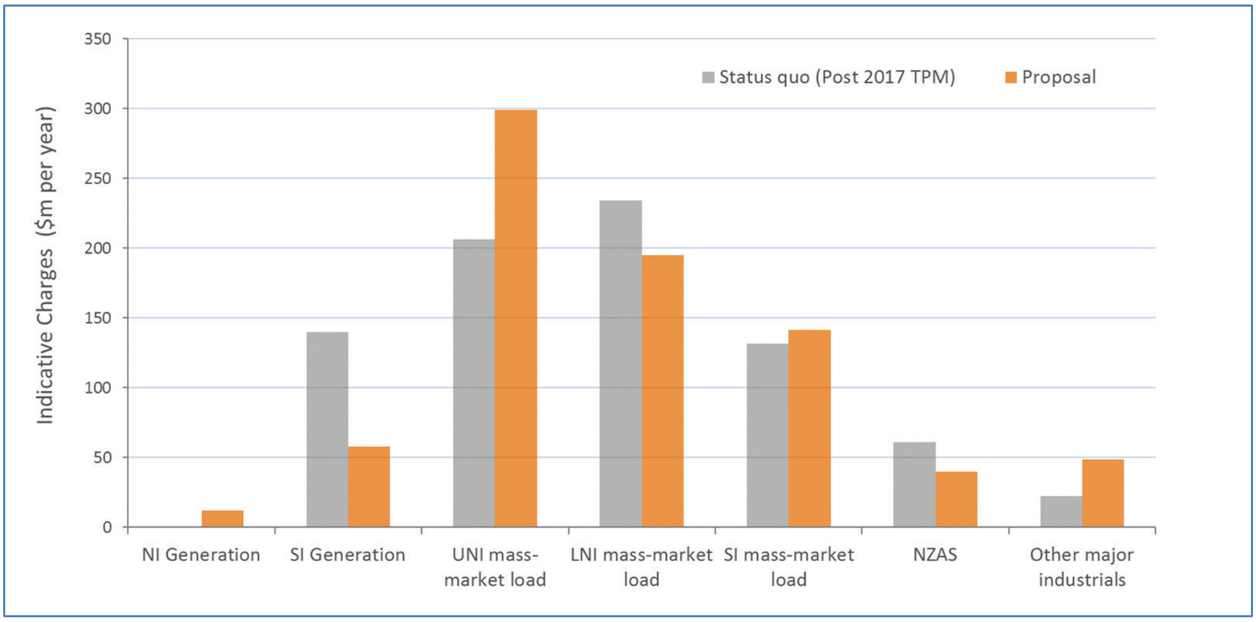
7.339 Figure 17 below shows the revenue recovered (excluding from connection charges) from different customer groups under the Authority's proposal relative to the status quo.

7.340 The modelling shows that under the Authority's proposal, charges would initially be greater for upper North Island load and other major industrials relative to the status quo, although this modelling does not take into account the proposed changes to the PDP, for which some major industrials may be eligible.

7.341 Charges would initially be greater for upper North Island load because of area-of-benefit charges for large recent investments. For other major industrials charges would increase because of a combination of the area-of-benefit charges for those major industrials located in the upper North Island and because some major industrials are able to substantially avoid the interconnection charge under the status quo.

7.342 The modelling shows the proposed charges would result in lower charges for generation, lower North Island and NZAS.

Figure 17: Transpower's regulated revenue modelled as being recovered from major customer groups under the Authority's proposal relative to the post-2017 status quo[237]

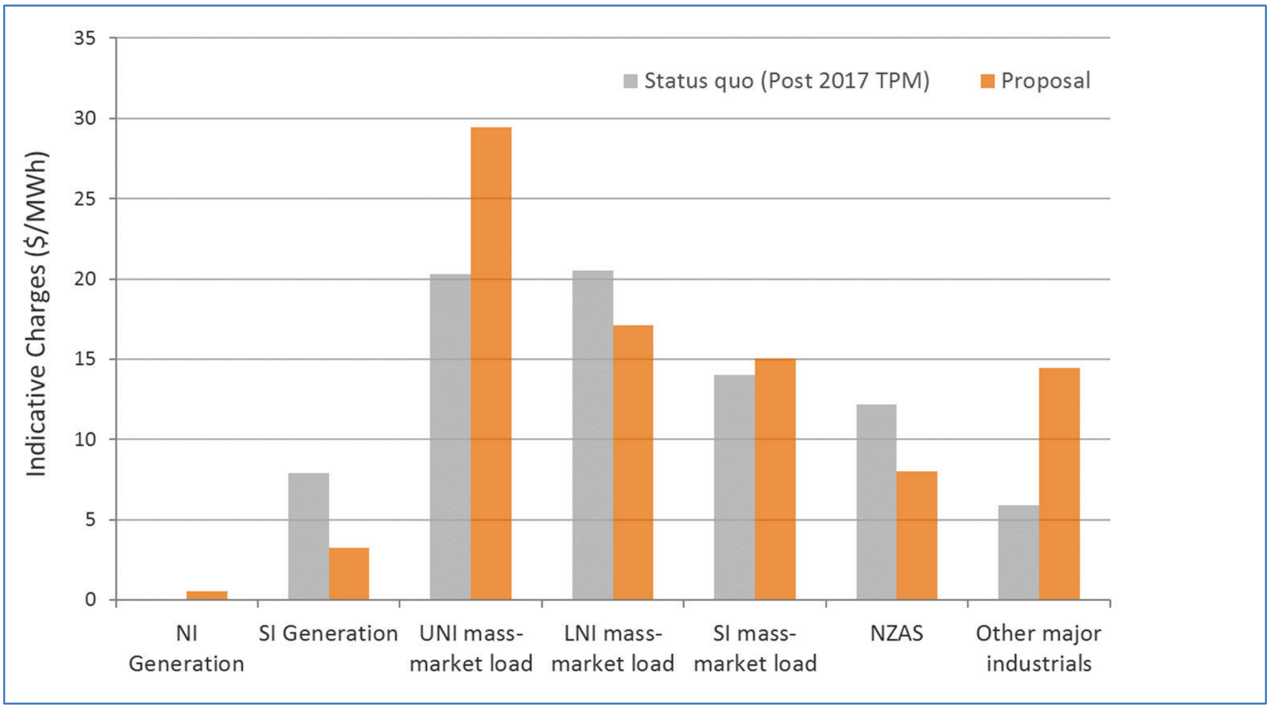


7.343 Figure 18 below shows charges to major customer groups in fully variabilised terms, relative to the status quo.

7.344 Figure 18 shows that, under the Authority's proposal, in fully variabilised terms the pattern of distribution of charges is similar to charges in aggregate, although charges for generation are lower than load. The lower charges for generation are because generation is not subject to the residual charge and also because it benefits less from the investments modelled than load.

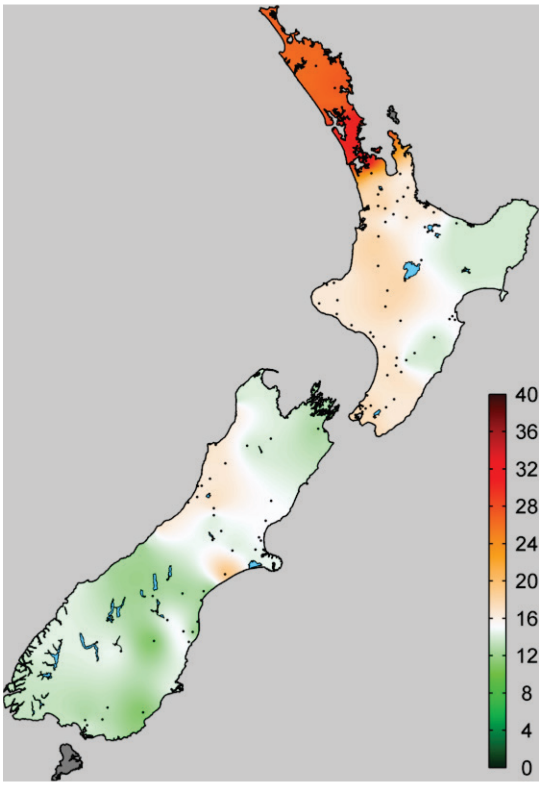
[237] That is, the status quo TPM updated to incorporate the changes resulting from Transpower's operational review.

Figure 18: Modelled transmission charges in fully variabilised terms ($/MWh) for major customer groups under the Authority's proposal relative to the post-2017 status quo



7.345 Figure 19 below shows a heat map showing regional incidence of charges on distributors under the Authority's proposal. The heat map does not include charges passed through to load by generators. The map indicates the initial incidence of the Authority's proposal is greatest for the upper North Island and, to a lesser extent, Counties, Hamilton/Northern Waikato, Horowhenua, Wellington, Tasman, Buller, Westland and Ashburton/Mid Canterbury. The reason for this pattern is the upper North Island benefits from several large recent investments subject to the area-of-benefit charge, while the other regions have a relatively high residual charge in variabilised terms because of a relatively low load factor.

Figure 19: Regional incidence of charges on distributors under Authority proposal in fully variabilised terms ($/MWh)



7.346 Figure 20 below shows the regional incidence of changes in transmission charges on distributors, relative to the status quo. It indicates that the largest increases in charges occur in the upper North Island, Ashburton/Mid Canterbury and West Coast and, to a lesser extent, Bay of Plenty[238]. The reasons for the change in incidence in the West Coast and the Mid-Canterbury/Ashburton area are that these areas have relatively low RCPD charges under the status quo and, closely related to that point, they each have relatively low load factors which means they would experience a relatively high residual charge in fully variabilised terms. For the upper North Island, the reasons are the same as for the pattern with the simple dollar impacts. The reason for the somewhat higher charges in the Bay of Plenty area is because this area has relatively low charges under the status quo.

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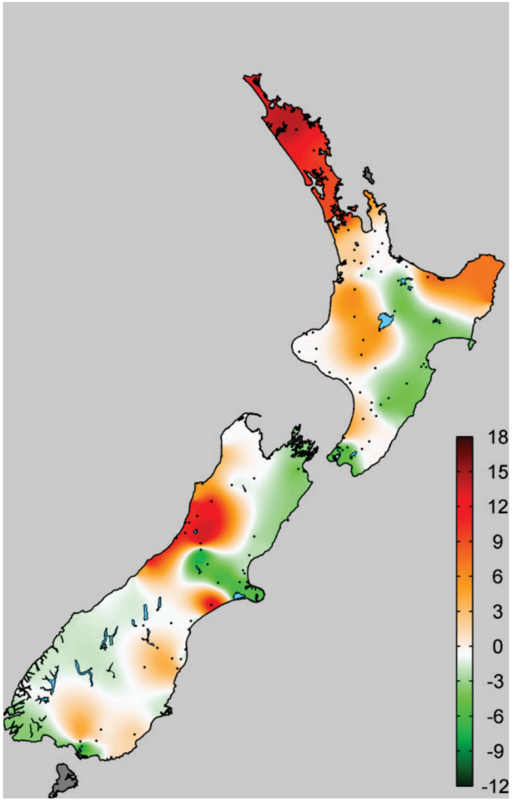
[238] Figure 20 also suggests charges increase in the Gisborne area. This is not the case, however, as charges would fall in this area. The reason the diagram shows an increase is because of the low number of nodes in the Gisborne area.

Figure 20: Regional incidence of changes in transmission charges on distributors in fully variabilised terms relative to status quo ($/MWh)



8 Cost-benefit analysis of the Authority's proposal

Introduction

8.1 This chapter provides a cost-benefit analysis (CBA) of the Authority's proposal. The chapter:

(a) gives a brief summary of the Authority's proposal, as set out in chapter 7

(b) describes the results of a CBA of the proposal that the Authority commissioned from Oakley Greenwood (OGW)

(c) reviews and discusses some aspects of OGW's CBA, and gives the Authority's overall conclusion of the net benefit of the Authority's proposal against a counterfactual of the status quo

(d) briefly assesses the net benefit of implementing the Authority's proposal relative to implementing a deeper connection based option.

8.2 The Authority is of the view that, in addition to the benefits and costs quantified by OGW, there are also some very substantial net benefits that have not been quantified. This chapter describes these benefits and provides an assessment of their importance relative to the net present value of the benefits quantified by OGW.

Summary of the Authority's proposal

Main components

8.3 There are four main components in the proposed guidelines:

(a) a connection charge

(b) an area-of-benefit charge

(c) a residual charge

(d) a prudent discount policy.

8.4 Although the deeper connection based option is not the Authority's preferred option, OGW was originally requested to assess it alongside, and as an alternative to, the Authority's proposal.

Additional components

8.5 Under the proposed guidelines, Transpower would also be required to consider whether to include any of the following additional components in the TPM:

(a) a requirement to treat assets in a particular way during staged commissioning

(b) a method for charging for assets when their classification changes due to new investments

(c) a method for allocating operational and maintenance costs on an actual cost basis, for assets in relation to which the connection charge or area-of-benefit charge applies

(d) an LRMC charge

(e) a kvar charge.

Code Changes

8.6 In addition, the Authority intends to propose an amendment to the Code in relation to LCE and network reactive support.

Summary of OGW's CBA results

8.7 The Authority commissioned OGW to undertake a CBA of the Authority's proposal and of a deeper connection option against a counterfactual of the status quo.[239] The status quo is the current TPM taking account of the changes that will be made as a result of Transpower's recent operational review.

8.8 OGW's full CBA is set out in Appendix C. It quantifies the major costs and some of the major benefits of the proposal and estimates the net present value of the economic costs and benefits from the Authority's proposal over a 20 year period using a discount rate of 8.0 per cent real.

8.9 This section summarises the OGW CBA. It focuses on the Authority's proposal against a counterfactual of the status quo.

8.10 The OGW CBA takes as its economic objective the Authority's interpretation of its statutory objective with respect to the TPM. It assesses that the revised TPM will result in:

(a) Economic benefits from more efficient future investment in services or equipment that may otherwise be substitutes for capacity-related transmission services, such as demand-side response, embedded generation and energy storage, thus leading to a reduction in the overall cost of providing electricity services to end customers.

(b) Economic benefits from more efficient future investment in electricity generation services. This occurs because transmission pricing better reflects the cost of its provision, so the sizing, location and timing of generation investment will better take that cost into account, thus leading to a reduction in the overall cost of providing electricity services.

(c) Economic benefits from more efficient pricing of historical grid investments currently subject to the interconnection and HVDC charges, leading to more efficient investment and consumption and to a reduction in inefficient exit.

(d) Economic benefits from more efficient quantities of transmission services being demanded by the market as a result of end users facing more efficient prices, thus leading to a reduction in the overall cost of providing electricity services.

[239] At the time the study was commissioned, the Authority had not formed a preference between the two approaches.

8.11 As well as these benefits, the CBA takes account of the incremental costs to Transpower and other electricity participants of administering and implementing the new TPM (including the costs of disputes), as compared to the status quo.

8.12 The quantitative CBA (presented in the tables below) takes into account the four main components of the proposed guidelines outlined in paragraph 8.3.

8.13 The CBA separately addresses each of the additional components outlined in paragraph 8.5. These are discussed further below.

8.14 Table 4 below highlights the results of the quantitative CBA of the Authority's proposal. In summary, the OGW CBA quantifies the net benefit of implementing the Authority's proposal, relative to the status quo, at $213 million[240].

Table 4: Summary of benefits for the area-of-benefit based TPM compared with the status quo

Type of benefit	Value (NPV)
Future investment in services that may be substitutes for transmission services	
Alternatives to transmission investment	$1,202,796
Deferrals to transmission investment	$3,010,839
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$313,601
Benefit from more efficient pricing of historical investments:	
Removing the HVDC injection charge based on MWh	$13,731,094
Replacement of the Regional Co-Incident Peak Demand (RCPD) charge with a charge based on physical capacity	$89,974,887
Introducing a more comprehensive PDP	$10,302,309
Net incremental and avoided costs	$2,040,441
NET BENEFIT (COST)	**$213,324,092**

Source: OGW

240 This assumes that there is a 50% probability that the two Rankine units at Huntly Power Station are retained. Because these units have a relatively low efficiency, this is a reasonable assumption given Genesis Energy's recent announcement that these units will be available until December 2022.

8.15 Table 5 below shows the results of the OGW sensitivity analysis. It shows that the results vary depending on the parameters that are changed. However, the results exhibit a positive benefit-cost ratio in all sensitivity analyses undertaken, namely:

(a) changing the discount rate to 6% and to 10%

(b) a decrease in the price of capital expenditure to 50% of the base case (but no change in the quantity of capital)

(c) a 50% reduction and a 50% increase in the proportion of future transmission investment that can be offset by diesel generation, relative to the base case

(d) a change in the evaluation period to 10 years and to 30 years

(e) an increase in the estimated implementation costs of 100%.

8.16 In addition, the sensitivity analysis shows a net benefit, not included in the above quantification, of $20 million to $66 million from more efficient investment in and timing of transmission projects as a result of more efficient scrutiny of those projects due to service-based and cost-reflective pricing.

Table 5: Sensitivity analysis of the net benefits of the Authority's proposal compared to the status quo

Scenario	**Net Benefit**
Base case: 8% discount rate, 20-year analysis	$213 million
Scenario	**Net Benefit**
1. 6% discount rate, 20-year analysis	$242 million
2. 10% discount rate, 20-year analysis	$191 million
3. 50% reduction in the price of capital[241]	$302 million
4. Scenario: 50% increase in diesel generation offset, 8% rate, 20 years	$217 million
5. Scenario: 50% reduction in diesel generation offset, 8% rate, 20 years	$210 million
6. 8% discount rate, 10-year analysis	$172 million
7. 8% discount rate, 30-year analysis	$258 million
8. Increased scrutiny	$233 million to $279 million[242]
9. 100% increase in implementation costs	$210 million

241 The OGW CBA describes this as "the cost of a given quantity of transmission investment".

242 The CBA gives an incremental net benefit of $20 million to $66 million. In this table, this is added to the base case benefit of $213 million and rounded to make the figure comparable to the other figures in the table.

OGW's assessment of the additional components

8.17 The CBA also provides an analysis of the five additional components outlined in paragraph 8.5. It concludes that:

(a) providing Transpower with the option in the future of including in the TPM a method to clarify charges for staged commissioning of connection assets would accrue positive net benefits

(b) requiring Transpower to include in the TPM clear rules about whether, and to what extent, connection assets that are connected by a new line become interconnection assets is likely to yield positive net benefits

(c) providing Transpower with the option of including in the TPM in future a method of allocating operational and maintenance costs for an asset to which the area-of-benefit or connection charge applies to the parties that pay charges in relation to that asset would be likely to yield net benefits

(d) providing Transpower with the option of including in the TPM an LRMC charge is likely to yield net benefits

(e) providing Transpower with the option of including in the TPM a kvar charge on a locational basis, should power factors deteriorate in future, is likely to yield net benefits.

OGW's assessment of the amending the Code for LCE

8.18 The OGW CBA concludes that, while it would depend on the actual design and the administration costs of implementing the change, amending the Code to change the treatment of LCE in the manner proposed by the Authority would appear to yield net benefits.

The Authority's view of OGW's CBA

8.19 As with any CBA, the OGW CBA makes a number of assumptions that influence the precise results it achieves. This section comments on some of these assumptions before forming an overall assessment of the proposal.

8.20 The OGW CBA:

(a) assumes that the price signals sent by the Authority's proposal are accurate. While they are unlikely to be perfectly accurate, the Authority is confident that the price signals sent by the Authority's proposal will be sufficiently service-based and cost-reflective to engender the type of response that OGW model.

(b) has an estimate of implementation costs that is lower than is likely to occur in reality. However, the sensitivity analysis shows that any reasonable estimate of the implementation costs would not significantly alter the net benefit estimated by the CBA.

8.21 Furthermore, the sensitivity analysis shows that the net benefit is large in all the scenarios modelled. This suggests that the conclusion that the net benefits quantified by the CBA are substantial and positive is robust.

8.22 As a result, the Authority is of the view that the OGW CBA provides a reasonable assessment of net benefits arising from the benefits and costs that it has quantified.

8.23 The Authority also accepts the conclusions of the OGW CBA about the additional components.

8.24 However, the Authority is of the view that the unquantified benefits from implementing the TPM, relative to the status quo, are also likely to be substantial and include the following (some of which OGW identified in its CBA):

(a) improved scrutiny of proposed transmission investment

(b) benefits from improved timing and specification of replacement expenditure

(c) reduced cost of unproductive disputes and reduced cost of uncertainty associated with a move to service-based and cost-reflective pricing

(d) benefits from not inefficiently encouraging or discouraging potential customers from entering the market

(e) benefits from the net benefits extending beyond the period modelled.

8.25 The following paragraphs expand on each of these points.

Improved scrutiny of proposed transmission investment

8.26 The OGW CBA discusses the benefits that charging service-based and cost-reflective prices will have for improving investment scrutiny and therefore improving the quality of investment. In brief, under service-based and cost-reflective prices, those who are expected to benefit from a proposed investment are charged the full cost of undertaking it. As discussed in chapter 5 (and in contrast to the current arrangements), this encourages Transpower's customers to focus on whether the investment is worthwhile. It also encourages them to support it if the benefits outweigh the costs and oppose it otherwise. This should substantially 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.[243]

8.27 The OGW CBA outlines these benefits. It concludes that "Quantifying a net improvement from increased scrutiny is problematic and our CBA has considered this matter via sensitivity analysis, but it is nevertheless certainly positive (and potentially material, even if it only comes about as a result of a small number of otherwise high cost but inefficient projects not being undertaken)." The results of the OGW sensitivity analysis is described in paragraph 8.15-8.16 above.

8.28 The Authority agrees that the proposal will substantially improve the scrutiny of investment proposals and so improve the quality of investment. However, the Authority is of the view that the benefits are likely to be much larger than the sensitivity analysis implies. As the OGW CBA notes, if the incentives provided by service-based and cost-reflective pricing stop just one major investment from inefficiently proceeding, that alone is likely to save more than the cost of implementing the Authority's proposal, and so justify its introduction.

[243] Economists will recognise this as an application of agency theory.

8.29 For example, there has been advocacy for undergrounding of Auckland transmission lines. The benefits of this undergrounding, if it proceeded, occur in the form of more efficient land use for narrow strips of land, and also aesthetic and environmental benefits. Transpower reported that there would likely be no improvement in transmission services as a consequence.

8.30 Transpower submitted to the Commerce Select Committee that undergrounding would have a capital cost of about $1.5 billion for the Auckland region. The Authority conservatively estimates that this would also increase operating costs of the grid by $75 million per year. The Authority's TPM proposal, which would have the effect of allocating the cost to the Auckland region, which means that Auckland consumers would ultimately bear the charge. The Authority notes that undergrounding projects may not meet the requirements under the Capex IM. However, if a separate regime was created for undergrounding investments, it is likely there would be strong pressure for beneficiaries to pay for those investments if investments under the Capex IM were subject to beneficiaries-pay, as would be the case under the Authority's TPM proposal. The Authority considers that making undergrounding subject to beneficiaries-pay is likely to make such investment much less likely to proceed. At a capital cost of 8%, the Authority calculates the cost savings from not proceeding with the project have a present value of $1.7 billion over 20 years. This is about $3,400 per Auckland household.[244]

8.31 As a result, the Authority's proposal creates strong incentives for Auckland consumers to oppose undergrounding.[245] Even if the Authority's proposal reduced the chance of the undergrounding proceeding by 1%, that alone would save an expected $17 million. This is more than the cost of implementing the Authority's proposal, and so justify its introduction. Similarly, if implementation of the Authority's proposal stopped even a small percentage of this undergrounding from proceeding, that alone is expected to save more than the cost of implementing the Authority's proposal, and so justifies its introduction.

8.32 Likewise, substantial savings would occur if implementation of the Authority's proposal creates incentives that prevents an inefficient major investment proposal from proceeding or even defers a major investment proposal for a number of years until it is efficient to build it.

8.33 For example, suppose there is a transmission project with a capital cost of $400 million and operating costs of $20 million per year, but whose benefits are equal to only 80% of its costs. Suppose that investment would proceed against the background of the existing TPM because parties do not have the incentive to engage with the Commerce Commission's grid investment approval regime, but that the increased scrutiny that would arise under the Authority's proposal would prevent or delay it occurring because the Commerce Commission is provided with information that contradicts Transpower's case for approval and/or affects key analysis parameters such as the demand and generation scenarios used in applying the investment test in the Capex IM. Then the benefits from

[244] Of course the charge would flow through to businesses as well as households, if businesses were assessed to benefit from undergrounding. Much of that increased charge would also likely flow through to consumers.

[245] This assumes that the present value of benefits is substantially less than $1.7 billion, which seems likely.

implementing the Authority's proposal—just from abandoning this one project—would have a net present value of $113 million over 20 years. A project of this size is not unusual.

8.34 Suppose the hypothetical project in the previous paragraph was currently inefficient as described in that paragraph, but becomes efficient after 5 years. Then the saving from deferring it until it becomes efficient has a net present value of $40 million.

8.35 These rough estimates reveal the potential for very large economic benefits to arise from the Authority's proposal.

Improved timing and specification of replacement expenditure

8.36 The OGW CBA expresses the view that the Authority's proposed guidelines will not affect the timing of replacement expenditure and so they have "Not ascribed any potential economic benefit to replacement expenditure in the base CBA." OGW does, however, acknowledge there is some uncertainty about this assumption.

8.37 The Authority regards this assumption as conservative. The Authority expects both the nature and timing of replacement and refurbishment expenditure to be affected by the price customers have to pay for it. Indeed, in 2015 the Authority heard directly from a transmission customer that it withdrew its objection to a proposed replacement investment when it was told it would not have to pay for it. The customer was objecting to the proposed replacement because it thought it might discontinue using the asset.

8.38 Total annual replacement and refurbishment expenditure is around $170 million per year, which is far higher than average major capex over the next five years (expected to be around $100 million per year). As with the examples for capital expenditure in the previous section, these figures suggest that there is substantial scope for savings on replacement and refurbishment expenditure.

Reduced cost of unproductive disputes and reduced cost of uncertainty

8.39 The OGW CBA expresses the view that because the Authority's new approach will be "well documented and understood, it would be expected that some costs associated with disputes and reviews of the TPM could be avoided in the future". It then adopts what it says is a conservative approach to quantifying the costs.

8.40 The Authority is of the view that the savings from reducing disputes are likely to be larger than the CBA suggests for two reasons. First, they are likely to be larger because the quantification is deliberately conservative. Second, they are likely to be larger because OGW does not take account of the nature of the charges on their acceptability. Specifically, OGW bases its estimate on the current cost of disputes.

8.41 The Authority is of the view that the way costs are recovered affects the acceptability of charges to those that are paying them. Material and rapidly rising charges that are not even roughly service-based and cost-reflective are likely to be the subject of on-going debate, unproductive lobbying and review compared with what would happen if the charges were service-based and cost-reflective.

8.42 Compared to the current TPM, the Authority expects that implementing the proposed TPM would have three efficiency effects. First, fewer resources would be diverted into unproductive advocacy for fundamental changes to the TPM regime. Second, it would reduce the uncertainty about what the charges will be in the future, and so improve incentives to invest. This is because there are likely to be less disputes about the nature of the TPM and so less uncertainty about its continued application in future Third, there are likely to be more resources devoted to engagement in the investment approval process. However, this has the potential to improve the efficiency of investment over time, with consequential efficiency benefits.

Efficiently encouraging or discouraging potential load customers from entering

8.43 The OGW CBA identifies and models the benefits of "a lower probability of some load customers inefficiently exiting the grid" as a result of the proposed revisions to the PDP. The benefit of this is estimated at $10 million.

8.44 This raises the question of entry. The current TPM is also likely to be precluding efficient entry of load grid users and encouraging inefficient entry of load grid users.[246] For example, areas where firms are paying total charges for transmission services that are lower than incremental cost are likely to be having entry and expansion that is inefficiently high.

8.45 It is difficult to estimate the cost of these effects as an estimate is required of the extent of entry and growth that would have occurred had the charges been service-based and cost-reflective (among other things). Nevertheless, it seems reasonable to assume that the costs would be of the same order of magnitude as the benefits from lowering the probability that some load customers inefficiently exit the grid, which OGW estimated to be about $10 million.

Actual period of net benefits extending beyond the period modelled

8.46 The OGW CBA models the benefits and costs for a period of 20 years from the time of implementation of a new TPM that complies with the proposed TPM guidelines. In reality, many of the investments in transmission assets will have a much longer life than this. The OGW modelling allows for this by reducing its estimate of the LRMC of transmission. This ensures that the trade-off between transmission and other forms of investment is appropriately modelled. However, it does not take account of the fact that benefits and costs will therefore continue well beyond the end of the modelling period. Thus the level of benefits will be proportionately larger than that modelled by the OGW CBA.

8.47 Table 5 above presents sensitivity analysis of the impact of altering the modelling period. Specifically, increasing the evaluation period from 20 to 30 years increases the present value by $45 million or 20%.[247] It can therefore be

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[246] The OGW CBA explicitly models the entry of generation customers.

[247] From table 5, the 30 year scenario has a benefit of $258 million, and the base case has a net benefit of $213 million. The difference between them is $45 million.

expected that the actual benefits will be substantially greater than the CBA assesses.

Conclusion: CBA of the Authority's proposal

8.48 The OGW CBA quantifies the net present value from implementing the Authority's proposal as $213 million compared with continuing with the status quo TPM. It exhibits a positive benefit-cost ratio in all sensitivity analyses undertaken.

8.49 The Authority's view is that the net benefit from implementing the Authority's proposal is likely to be considerably larger than the quantitative net benefits estimated by OGW. This assessment is based on the qualitative net benefits identified above.

Comparison of the Authority's proposal with the deeper connection option

8.50 The OGW CBA considers the Authority's proposal and the deeper connection option on an equal footing, and compares the benefit of both relative to the status quo. For completeness, this section briefly compares the Authority's proposal with the deeper connection option.

8.51 The OGW CBA quantifies the net present value from implementing the Authority's proposal as $213 million and the net present value from implementing the deeper connection option as $208 million. Thus the net benefit of implementing the former as compared to the latter is quantified as $5 million. While this favours the Authority's proposal, the difference is small.

8.52 The OGW CBA also assesses but does not quantify some other effects of the proposed TPM compared to the deeper connection option. These are summarised at the end of the Executive Summary in the OGW CBA. They include:

(a) The area-of-benefit charge is adjusted to provide a cost-reflective marginal price signal for a new investment. In comparison the deeper connection charge option simply allocates the full cost of the investment according to use, which is less efficient.

(b) The deeper connection charge option allocates charges based on power flows; that is, based on use rather than on benefit. This undermines the potential benefits from moving to service-based and cost-reflective pricing.

(c) The deeper connection charge option would be calculated based on a 5-year rolling average of flows which is effectively a MWh charge. Using a variable price signal to recover the cost of historical investments may lead to inefficient outcomes, by discouraging efficient use of the grid.

(d) The deeper connection charge is only levied on major users of an investment. This reduces the coverage of the price signal and reduces the incentive on Transpower's customers to scrutinise investments, relative to the Authority's proposal.

(e) The deeper connection charge option creates a locational distortion which may distort distributor's connection decisions, as well as distorting the locational decisions of new generators and direct consumers.

8.53 The Authority agrees with these points. The deeper connection option is more service-based and cost-reflective than the status quo, but much less so than the OGW CBA assumes. As a result, both the quantitative benefits are likely to be less than the OGW modelling suggest, and many of the other qualitative benefits assessed for the Authority's proposal in paragraph 8.24 above would be smaller if the deeper connection charge was implemented. For example, it is likely to generate less benefit from encouraging more efficient replacement expenditure.

8.54 In summary, the Authority's view is that, considering the qualitative and quantitative benefits and costs together, the Authority's proposal shows substantial net benefits relative to the deeper connection option and is preferred over it.

Conclusion

8.55 The OGW CBA quantifies the net present value from implementing the Authority's proposal as $213 million compared with continuing with the status quo. It exhibits a positive benefit-cost ratio in all sensitivity analyses undertaken.

8.56 The Authority's view is that the net benefit from implementing the Authority's proposal is likely to be considerably larger than the quantitative net benefits estimated by OGW. This assessment is based on the qualitative net benefits the Authority has identified above for the Authority's based proposal compared to the status quo.

8.57 In addition, giving Transpower the option of introducing the additional components, will, if Transpower chooses to propose them to the Authority, have positive net benefits.

9 Evaluation of alternative means of achieving the objectives

Introduction

9.1 As described in chapter 3, the Act requires that the Authority prepare and publicise a regulatory statement, before amending the Code. The regulatory statement must include, among other things, an evaluation of alternative means of achieving the objectives of the proposed amendment.

9.2 This paper consults on proposed guidelines for Transpower to follow in developing the TPM.[248] Because the proposed guidelines are likely to lead to a proposal for a new TPM (and therefore a Code amendment proposal), the Authority has set out in this chapter alternative means of achieving its objective for the TPM.

9.3 The alternatives have been assessed against a counterfactual of the status quo TPM (ie, as mentioned earlier), including the changes that will be made as a result of Transpower's operational review. The alternatives have also been assessed against the Authority's proposal.

9.4 During the course of the TPM review, the Authority has considered a range of options for addressing the problems identified in relation to the current TPM. In particular, the Authority has considered:

(a) the options proposed by the TPAG

(b) the proposal in the October 2012 issues paper, based on applying a Scheduling, Pricing and Dispatch (SPD)-based charge for Pole 2 and for all investments approved since 28 May 2004 and costing more than $2m

(c) the alternatives in section 6 of the October 2012 issues paper[249]

(d) four beneficiaries pay options considered in the beneficiaries pay working paper

(e) the Base Option, Base Option + LRMC, and Base Option + SPD in the options working paper, with two different applications of those options

(f) the proposal in this second issues paper but with a deeper connection charge instead of the area-of-benefit charge.

9.5 In addition, submitters have suggested a range of alternatives to the options proposed by the Authority.

9.6 Having taken into account previous analysis and submissions made during the TPM review so far, this chapter evaluates the following potential alternatives to address the problems that the Authority has identified with the current TPM:

(a) the Authority's proposal with a deeper connection charge rather than the area-of-benefit charge

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[248] As discussed in chapter 3, this paper also discusses Code amendments that are related to (but not part of) the TPM.

[249] Readers are referred to section 6 of the first issues paper for an in-depth evaluation of these alternatives.

(b) alternatives that could be implemented under the existing TPM guidelines, if Transpower undertook one or more further reviews

(c) a tilted postage stamp charge

(d) an SPD-based charge

(e) a broad-based, low rate charge for each island or for Transpower's four transmission pricing regions, combined with an HVDC charge levied more broadly than the status quo.

Deeper connection-based version of the Authority's proposal

Description

9.7 This option would be the same as the Authority's proposal but with a deeper connection charge instead of an area-of-benefit charge. This option was examined in detail by the Authority and assessed through cost-benefit analysis. The details of the deeper connection charge considered by the Authority are set out in Appendix E.

9.8 For clarity, the main components of this option are:

(a) the existing connection charge, subject to the possible inclusion of additional components 1-3 from the Authority's proposal

(b) the deeper connection charge set out in Appendix E

(c) a residual charge on load calculated on a capacity basis

(d) an extended prudent discount policy that is the same as that described in chapter 7.

9.9 As under the Authority's proposal, Transpower would also be required to consider whether to include any of the following "additional components" in the TPM:

(a) a method for determining how transmission assets are classified during staged commissioning

(b) a method for charging for transmission assets when their classification changes due to new investments

(c) a method for allocating operational and maintenance costs on an actual cost basis, for assets in relation to which the connection charge or deeper connection charge applies

(d) an LRMC charge

(e) a kvar charge.

9.10 This option would also involve progressing the LCE Code change and change to the power factor in the Connection Code.

Evaluation

9.11 This option would be lawful, practicable, and would recover Transpower's costs.

9.12 This option is likely to be more efficient than the status quo. As discussed in chapter 8, the Oakley Greenwood cost-benefit analysis quantifies net benefits of $208 million in net present value terms from implementing the deeper connection option, but also notes some unquantified benefits and costs which would modify this assessment of net benefits somewhat. The Authority broadly accepts this analysis.

9.13 If this option was implemented, depending on the final detail of the deeper connection charge, it would result in transmission charges that to a greater or lesser extent:

(a) Are service-based:

Customers would face deeper connection charges only for assets that provide transmission services to the regions in which the customers are located. The deeper connection charge component would adapt to changes in flows across the grid as a result of investment and connection / disconnection.

(b) Are cost-reflective:

This option would better reflect the cost of providing services to each customer compared to the status quo. In particular, the deeper connection charge for each customer would be at a level that reflected the cost of the assets that support the provision of transmission services to or from the region in which each customer is located.

(c) Support the discovery of the need for efficient transmission investment through the transmission investment approval process:

Under this option, customers would have much stronger incentives to scrutinise transmission investments than they would under the status quo. That is because of the effect of the deeper connection component in particular. The main parties paying a deeper connection charge for an asset serving a particular region would be the parties that were mainly receiving transmission services from the asset. This is in contrast to the status quo, where the costs of an investment are spread across all load in the case of interconnection, and across South Island generators in the case of the HVDC.

(d) Are durable:

There would be a correlation between the customers that receive services from an asset and the customers that pay for that asset. This would be maintained by the proposal to review the charges periodically. Unlike the HVDC and interconnection charge, this option would better ensure that customers receiving transmission services from the asset would contribute to its cost.

9.14 The Authority has not proposed this option, however, because the cost-benefit analysis indicates it would provide lower net benefits than the Authority's proposal.

9.15 This option also has disadvantages that are less likely to arise under the Authority's proposal:

(a) Customers may face deeper connection charges that exceed the benefit they will receive. The Authority sought to design the deeper connection charge to minimise the chance of this happening. This included incorporating a cut-off level for the Herfindahl-Hirschman Index (HHI) of the shares of power flows, and allowing assets to be optimised down under certain circumstances.

(b) It is likely to be less effective at promoting efficient investment. The deeper connection charge would only partially recover the costs of most assets subject to it, with remaining costs recovered through the residual charge.

Further, under this option, investments associated with flows from a large number of regions would potentially be fully recovered through the residual charge, even though beneficiaries may be more concentrated, eg, all beneficiaries located within a region or within an island.

In addition, the deeper connection charge would be poor at promoting efficient investment when the new investments are large, as the charge would be poorly aligned with the distribution of benefits from such investments. This is because the addition of large assets to the grid can materially alter power flows over other parts of the grid (altering the deeper connection charges for those assets). The addition of large new assets to the grid can materially alter nodal prices around the grid, but the deeper connection charge ignores the benefits that arise from those pricing effects even though they would be benefits that users would be prepared to pay for.

(c) The identification of deeper connection assets and the parties subject to the charge is relatively complex and is likely to result in distortions to behaviour. In particular, the proposal to periodically review the charge, while having the benefit of ensuring charges remain somewhat service-based, has the cost of inefficiently adding to nodal prices and so distorting grid use. While the Authority sought to design the charge to keep such distortions to a minimum, some distortion is likely to remain.

Alternatives under the existing guidelines

Description

9.16 This option would involve development of charges under the existing guidelines[250] to address the problems identified by the Authority. The key components of the existing guidelines are:

(a) nodal pricing is a key component of transmission pricing, which Transpower must take into account when preparing a TPM

(b) charging for connection on a ‘deep’ connection basis

(c) charging for existing and new interconnection assets on a postage stamp basis

250 Electricity Commission, Guidelines for Transpower, Transmission Pricing Methodology, 24 March 2006. Available at: https://www.ea.govt.nz/dmsdocument/2990.

(d) reviewing the use of peaks as the basis for calculating the interconnection charge

(e) charging all South Island generating stations that inject into the grid for the HVDC link, and for any replacement or upgrade of that link

(f) a prudent discount policy to avoid inefficient bypass of the existing grid.

9.17 In addition, although the existing guidelines do not specify that interconnection revenue should only be recovered from load, this is implied by reference to “grid exit point”, “offtake peaks” and “GXP loads” in the guidance on the interconnection charge. The existing guidelines also arguably imply that interconnection charges on load must be calculated on a peak basis. For example, the guidelines state that Transpower should review the number of peaks in the charge.

9.18 The Authority considers that an alternative TPM within the existing guidelines could feasibly consist of:

(a) a revised connection charge that would extend the definition of connection deeper into the grid

(b) an interconnection charge levied on all load with the charge set on regional coincident peak demand or split in some proportion between the existing interconnection charge and a per MWh charge on load

(c) the HVDC charge as amended through Transpower’s operational review, possibly with different rates of charge for generators in the upper versus lower South Island

(d) the existing prudent discount policy.

9.19 Several alternatives to the amendments to the TPM that resulted from Transpower’s TPM operational review were considered during that review by both Transpower and the Authority. These were, however, not developed further because either Transpower’s proposals were assessed as more efficient, or more efficient alternatives could be considered if the guidelines were changed.

9.20 Under this option, the Authority's proposed approach to LCE and the power factor change as described in chapter 7 could also be implemented.

Evaluation

9.21 This option would be lawful, practicable, and would recover Transpower’s costs. It has the advantage that it would not require new guidelines.

9.22 However, as noted above, the existing guidelines are drafted on the basis that interconnection charges are applied to load rather than to load and/or generation. Further, while a deeper definition of connection is possible (so as to reduce the revenue recovered via interconnection charges), the Authority considers that the existing guidelines present a barrier to the development of charges that would address the problems of:

(a) inefficient transmission investment

(b) a TPM that is not durable.

9.23 In particular, the existing guidelines mean the approach under the status quo of recovering the costs of an interconnection investment from a postage stamp charge on load would have to continue. As noted in the problem definition, this is likely to result in excessive demand for transmission investment because:

(a) the charges for interconnection investments would be spread across all load, rather than just those parties being supplied with the transmission services enabled by the investment

(b) to the extent that an investment provides transmission services to generators, and is recovered through the interconnection charge, they would pay nothing.

9.24 In addition, the development of charges under the existing guidelines would require that the revenue requirements for the HVDC continue to be recovered solely from South Island generators. This would mean that HVDC charges developed under the existing guidelines would result in a TPM that continues the problems identified in chapter 6—namely, a TPM that:

(a) fails to promote efficient transmission investment

(b) is not durable.

9.25 In particular, other parties benefiting from HVDC upgrades, such as North Island load customers, would continue to have an incentive to lobby for more HVDC investment than may be efficient, as those parties would not have to pay for such investment but would receive the benefits in terms of lower wholesale electricity prices and higher reliability levels.

9.26 Further, the existing guidelines do not provide for flexibility to introduce additional, potentially desirable, components such as:

(a) a kvar charge to incentivise power factor exacerbators to correct or improve their power factors

(b) addressing possible incentives for inefficient investment through an LRMC charge, because the guidelines prevent different charges in different regions (although the effective rate of the charge can be varied to a limited degree by, for example, altering the number of periods that RCPD is calculated between regions) and restrict the interconnection charge to load and the HVDC charge to South Island generation

(c) addressing incentives for inefficient behaviour resulting from transmission charges, except to the extent that this is addressed through the prudent discount policy.

9.27 In conclusion, the problems that the Authority has identified with the TPM (as amended as a result of Transpower's operational review) could not be addressed through developing new charges under the existing guidelines.

A tilted postage stamp charge

Description

9.28 This option would involve new TPM guidelines to provide for a TPM that consisted of a connection charge, and an interconnection and an HVDC charge set on a postage stamp basis, but with the rate of the charge varying between regions. The 'tilt' of the postage stamp could be set according to one of the following:

(a) The LRMC of providing transmission services to each region. The LRMC could be calculated according to the average incremental cost (AIC) method. This would provide a constant rate of charge that would only change if there was a change to underlying demand or planned investment, and so would provide a relatively predictable charge. An alternative to this would be a peak charge, with the range of the charge set at a level approximating the LRMC for each region.

(b) The revenue requirements or cost of assets providing transmission services to a region and/or from which a region benefits.

(c) An approximation of the cost of providing transmission services to a region, eg a rate set according to the length and capacity of transmission lines servicing a region (ie, "MW miles").

9.29 A variation on the tilted postage stamp would be, in addition to a connection charge, an LRMC charge and a postage stamp residual charge. The LRMC charge could be set according to any of the MIC, LRIC or AIC methods. The combination of the postage stamp residual charge and LRMC charge would provide the tilt, ie, the differential in charges between each region. This has the potential to provide a more accurate signal about the cost of future investment than manipulating the effective rate of the current interconnection charge, such as varying the number of periods over which it is calculated. The residual charge would recover all of Transpower's maximum allowable revenue (MAR) except to the extent this was recovered through the LRMC charge. This variation is one version of a "two-part" charge favoured in the economics literature.

9.30 In addition, this option would include new guidelines that would provide for a TPM including the following:

(a) the PDP as proposed in this paper

(b) the connection charge, as described in this paper, including additional components 1–3 described in chapter 7

(c) as an additional component, the kvar charge as proposed in this paper.

9.31 Under this option, the Authority's proposed approach to LCE and the power factor change as described in chapter 7 could also be implemented.

Evaluation

9.32 This option would be lawful, practicable, and would recover the cost of Transpower's regulated transmission services.

9.33 This option is likely to be more efficient than the status quo. Depending on the variation of the tilted postage stamp, it would result in transmission charges that:

(a) are adaptive and better promote efficient transmission investment, as the charge to a region would only increase where the cost of providing transmission services to that region increased or, in the case of LRMC-based variations, where the future costs of providing transmission to the region increased

(b) are more cost-reflective, as the charges would either better signal future investment costs (in the case of an LRMC-based tilted postage stamp) or better reflect the cost of providing transmission services to the region

(c) are more durable, as parties would face charges that better reflect the benefit they receive from transmission assets and/or the incremental cost of providing them with transmission services, so parties would have less incentive to lobby for fundamental change to the TPM.

9.34 However, a tilted postage stamp is likely to be less effective than the Authority's proposal at addressing the problems identified by the Authority because:

(a) It would spread the costs of providing transmission services without specifically determining who receives those services and whether they benefit from those services (ie, it is less service-based than the Authority's proposal). This means the tilted postage stamp approach would be less effective than the Authority's proposal in the promotion of efficient transmission investment.

(b) An LRMC-based tilted postage stamp charge would rely solely on LRMC charges for the promotion of efficient transmission investment, the efficiency of which is dependent on the accuracy of demand and transmission investment forecasts. In contrast, the area-of-benefit charge sets the rate of charge based on actual investments that have occurred, which makes it more cost-reflective than an LRMC-based charge.

(c) Depending on how the charge was allocated between customers, it might continue to inefficiently impact on grid use.

An SPD-based charge

Description

9.35 This option would involve new TPM guidelines that would provide for a TPM consisting of:

(a) a connection charge, as proposed in this paper, including the additional components 1–3 described in chapter 7

(b) the PDP as proposed in this paper

(c) a kvar charge as proposed in this paper

(d) an SPD charge as initially proposed in the October 2012 issues paper, and subsequently developed in the beneficiaries pay and options working papers

(e) a residual charge, as proposed in this paper.

9.36 Under this option, the Authority's proposed approach to LCE and the power factor change, as described in chapter 7, could also be implemented.

Evaluation

9.37 This option would be lawful, practicable, and would recover Transpower's costs.

9.38 This option is likely to be more efficient than the status quo and better promote efficient transmission investment. Depending on the version of the SPD charge adopted, it would result in transmission charges that to a greater or lesser extent:

(a) Are service-based, as charges would be levied only on parties receiving actual benefits from transmission investments. This would mean that users of the interconnected grid have incentives to support and make efficient investment decisions, as the SPD charge incentivises them to access no more of the transmission service than is justified by their private benefit.

(b) Are more cost-reflective, as the level of the charge would be more based on the incremental cost of providing transmission services to groups of customers than the status quo. Charges for groups of customers would only increase when an investment occurred and those customers benefited from that investment.

(c) Are more durable, as parties would pay no more than the private benefit they receive from a transmission investment except to the extent required to pay residual costs. This is in contrast to the status quo where a party's charges may increase as a result of a new transmission investment even if they do not benefit from the new investment.

9.39 However, as was noted extensively in submissions,[251] there is a risk the SPD charge could distort bids and offers in the wholesale market, potentially having a significant negative impact on the efficiency of the wholesale market. Under the Authority's proposal, Transpower is required to propose a method for allocating the area-of-benefit charge and could propose to do so based on a forecast SPD approach or based on other methods such as an economic model (see the discussion under the heading "Discussion: responsibility for developing the methods" in chapter 7). Since Transpower has other options for modelling benefits, a forecast SPD approach could not be more efficient than the Authority's proposal.

9.40 The Authority's proposal is also more cost-reflective than the SPD-based option because the full cost of each eligible investment would be recovered from the area-of-benefit charge. In contrast, the SPD-based charge was capped at the half-hourly or daily value of benefits of each investment, with the residual recovered through the residual charge. This means the area-of-benefit charge provides more efficient incentives for parties to support and make operational and investment decisions that take into account the full cost of future grid investments.

9.41 The Authority's proposal is also more durable than the SPD-based option because the area-of-benefit charge allocates charges to parties that receive net private benefits over the lifetime of an investment. Provision has been made for

[251] For example, in submissions on the beneficiaries-pay working paper: Contact (p.2), Electricity Networks Association (p.6), Powerco (p.2), and in submissions on the first issues paper: Genesis (p.4, 7), Mighty River Power (p.77), Vector (p.4, 14).

the area-of-benefit charge to change when there is a material change in circumstances. In contrast the SPD-based option would allocate charges to parties based on their short-term benefits, which means parties that do not benefit over the longer term from an investment would also pay the SPD-based charge.

A broad-based, low rate charge for each island or for four transmission pricing regions combined with a broadly levied HVDC charge

Description

9.42 This option would involve new TPM guidelines that require that the TPM:

(a) set a broad-based, low rate charge in each island, or in each of the four transmission pricing regions, based on the revenue requirements of the assets in the island or region, or the assets serving the region

(b) include an amended HVDC charge applied to a broader set of customers than the current HVDC charge, such as all beneficiaries of the HVDC

(c) include the connection charge, as described in this issues paper, including the additional components 1–3 described in chapter 7

(d) include the kvar charge, as proposed in this paper.

9.43 Under this option, the Authority's proposed approach to LCE and the power factor change, as described in chapter 7, could also be implemented.

9.44 The option could also include a charge to provide a signal to defer transmission investment, such as an RCPD charge with the rate set according to the revenue to be covered from each island or region. The option could also consist of a combination of such a charge and a more ‘fixed’ charge, such as a capacity-based charge.

Evaluation

9.45 This option would be lawful, practicable, and would recover Transpower’s costs.

9.46 This option is likely to be more efficient than the status quo. The efficiency of the HVDC component would be similar to the Authority’s proposal if it was allocated to parties in proportion to their share of the net long-term benefits parties are expected to receive from the HVDC.[252]

9.47 However, the option is likely to be less efficient than the Authority’s proposal in relation to non-HVDC costs for similar reasons to those applying to a tilted postage stamp charge—that is, that it would involve:

(a) More spreading of the costs of providing transmission services, implying less effective promotion of efficient transmission investment and potentially greater distortion to the use of the transmission grid, as the charges would

[252] Recall that the list of eligible investments for the area-of-benefit charge includes all HVDC investments.

reflect less accurately the cost of providing transmission customers with the transmission services that they receive.

(b) To the extent that the option relied on a peak charge to promote efficient transmission investment, the efficiency of the charge would depend on the extent to which the signal reflected the benefit of deferring grid investment. An RCPD-based charge would be less efficient than a capacity-based allocator because charging on the basis of RCPD takes no account of the extent of spare capacity on transmission circuits.

9.48 This option would therefore be less efficient overall than the Authority's proposal.

Conclusion

9.49 In conclusion, the Authority considers that the alternatives it has evaluated in this chapter would be less efficient than the Authority's proposal and would therefore be less effective in promoting the Authority's statutory objective.

10 Evaluation of the proposal against the Authority's statutory objective

Introduction

10.1 This chapter sets out an assessment of the proposal for the TPM and Code changes against each limb of the Authority's statutory objective. Before doing so, it summarises key aspects of the approach to the assessment.

10.2 The Authority's statutory objective in section 15 of the Electricity Industry Act is to "promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".

10.3 Consistent with the Authority's interpretation of the statutory objective, the framework for decision-making about options for the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers. This recognises that competition is an important tool to encourage efficient outcomes, and that measures that affect reliability should encourage efficient trade-offs between the costs and benefits of reliability.

10.4 'Overall efficiency' refers to both efficient operation of and efficient investment in the electricity industry – the grid, generation, and the demand-side.

10.5 For the avoidance of doubt, reference to efficiency or 'overall efficiency' includes allocative, productive and dynamic efficiency. Broadly, allocative and productive efficiency refer to situations where production technology is static whereas dynamic efficiency refers to the efficient creation and adoption of new ideas and technology.[253] As the adoption of new ideas and technologies typically requires investment (either in people through education and training or in physical capital embodying new ideas and technology), dynamic efficiency is essentially about promoting efficient investment choices.

10.6 In regard to long-term benefit of consumers, the Authority considers that its primary focus is to promote dynamic efficiency, which includes:

(a) taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in the electricity industry, by both suppliers and consumers, and

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[253] More specifically, allocative efficiency occurs when consumers make consumption choices that result in producers supplying them the combination of goods and services that they most value (given the true costs of supply). Productive efficiency occurs when producers produce maximum output for a given value of inputs, or alternatively, when producers minimise their input costs to produce a given level of output. As capital is one input used in production, productive efficiency includes making efficient investment in capital goods that embody existing technologies. The distinction between productive and dynamic efficiency is important, as it is well-established in the economics literature that investments in education and training or in physical capital that embody new ideas and technology (ie, dynamic efficiency) are the primary sources of long-term growth in living standards. More efficient combinations of capital, labour and other inputs (ie, productive efficiency) can also result in higher growth rates in living standards but not indefinitely.

(b) taking into account the durability of the industry and regulatory arrangements in the face of high impact low probability events. [emphasis added]

Assessment of the proposal against overall efficiency—positive effects

10.7 Chapter 8 outlines the overall economic gains from the proposal, as assessed using a cost-benefit analysis. This chapter provides a more detailed description of:

(a) how the various components of the proposal contribute to efficient investment in the electricity industry

(b) how the various components of the proposal contribute to efficient operation of the electricity industry

(c) how the proposal enhances the durability of the TPM and so efficiency.

Facilitation of efficient investment in the electricity industry

10.8 The Authority's proposal facilitates efficient investment in the electricity industry through introducing a series of interrelated changes to the TPM that will support more efficient investment.

Connection charge

10.9 The connection charge already provides parties with incentives to take the connection costs into account in their own investment activity and to seek connection options that most cost-effectively meet their needs. It also provides them with incentives to seek out the parties that are best able to meet those needs. An assessment against the objective of facilitation of efficient investment is provided below for the three additional components that have implications for the connection charge: staged commissioning, a method for charging for assets when their classification changes due to new investments, and charging for operating and maintenance on an actual-cost basis.

Area-of-benefit charge

10.10 The area-of-benefit charge will mean the beneficiaries of investments that are subject to the area-of-benefit charge will pay for those investments and associated services. This means that they will have the incentive to take the cost of those investments and services into account in their own investment activity and to seek the most efficient investment options overall.

10.11 Unlike with the current postage stamp interconnection charge, the area-of-benefit charge will mean that the potential beneficiaries of a particular investment proposal will face incentives to reveal the real benefits to them of various investment options. They will have the incentive to support the investment if its benefits to them outweigh the cost they have to pay for it and to oppose it if they do not.

10.12 Because the major beneficiaries from a proposed investment will have a substantial stake in ensuring the investment is efficient, they will have a strong incentive to participate in Transpower's decision-making process on the investment. Conversely, because those who are not beneficiaries of a proposed transmission investment will not incur an area-of-benefit charge for it, the charge does not encourage them to inefficiently oppose the investment.

10.13 Together these considerations will 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 will make it less likely that decisions are made to proceed with an investment when it is not justified, and less likely that decisions are made to not proceed with investments that are justified. It also improves the chances of avoiding investments that are more expensive than they need to be.

10.14 As discussed in chapter 8, the sensitivity analysis in the cost-benefit analysis suggests a benefit from \$20 million to \$66 million from this. Also, as discussed in chapter 8, the Authority has good reason to judge that the economic benefits of greater scrutiny to be much higher than suggested in Oakley Greenwood's cost-benefit analysis.

10.15 In addition, as described in chapter 6 on the problem definition, the poor price signals generated by the current TPM are incentivising inefficient use of the grid and inefficient investments.

10.16 In addition, more efficient transmission investment will facilitate more efficient investment elsewhere in the industry, as it will alter the economics of transmission compared with alternatives such as generation, distribution and natural gas transmission (which is outside the electricity industry but relevant to economic efficiency).

10.17 Because the beneficiaries of a particular investment would be reassessed where there has been a material change in circumstances and the area-of-benefit charge adjusted accordingly, this charge would continue to promote efficient investment over time. That is, the area-of-benefit charge will continue to be cost-reflective.

10.18 The area-of-benefit charge also better complements the connection charge than the current "postage stamp" interconnection charge. The connection charging regime results in the beneficiaries of connection assets largely paying the full cost of those assets. Because they will also pay the area-of-benefit charge on any interconnection investments that they benefit from, their ability to shift costs to other parties is reduced, and so the incentive to seek to have connection investments reclassified as interconnection investments is also reduced.

10.19 The ex-ante determination of benefits under the proposed area-of-benefit charge, and the limited ability for the charges to be re-determined, minimises the risk of distortions to the use of the interconnected grid relative to the current interconnection and HVDC charges, which are calculated according to peak demand and injection respectively (although going forward the HVDC charge will be calculated according to average injection). Since benefits and therefore charges are determined on an ex ante basis, parties would be unable to alter their charges by changing their use of the interconnected grid. This is in contrast to the status quo where parties can alter their charges through changes in peak use or, in the case of the HVDC, average use. As discussed later in this chapter, nodal prices (possibly supplemented by an LRMC charge) provide an efficient signal for use of the grid. This means peak charges are likely to be inefficient. This means the area-of-benefit charge is likely to promote productive efficiency, as the interconnected grid is used more efficiently.

Residual charge

10.20 The proposed residual charge applies to load only and is allocated on the basis of historical physical capacity. It is also collected from a wide base of load customers. As a result, a customer's use of and benefit from a particular investment is not much affected by the residual charge they have to pay. The customer therefore has little incentive to alter their use of interconnection investments as a result of the residual charge (although it may affect incentives to alter their capacity—see negative effects below).

Prudent discount policy

10.21 It is proposed to change the prudent discount policy (PDP) to allow prudent discount contracts to extend for the life of the relevant asset. This should improve investment efficiency by increasing the certainty of the customer receiving the prudent discount that the discount will not be revoked after they have committed to investment (although a discount that is linked to market conditions faced by a customer may be reduced or suspended for a period in the event that market conditions improve).

10.22 It is also proposed to extend the PDP to more situations where a customer might otherwise be inefficiently incentivised to disconnect from the grid. Although the new TPM and the Code will make it less likely that situations will arise where a consumer may face incentives to inefficiently disconnect from the grid, it may still happen. Examples include:

(a) if the customer has incentives to build transmission to disconnect from the grid because the charges they face are greater than standalone costs, and the charges faced by the customer are inefficiently high (ie, the charges the customer should face are lower than standalone costs)

(b) if the customer has incentives to build generation to disconnect from the grid where that is not efficient overall.

10.23 The extension of the prudent discount policy will allow a prudent discount to be offered in such situations. This should improve efficiency.

Additional components

10.24 As is noted in chapter 7, the proposed guidelines would provide for five additional components. These are discussed further below. As discussed in chapter 8, the cost-benefit analysis assesses all five components as having net benefits. However, they would only be implemented if Transpower determines (and the Authority agrees) that it is in fact efficient to introduce them, having regard to both the benefits and costs, including administration and compliance costs.

10.25 The following five subsections describe how the additional components may promote efficiency gains that exceed the costs of implementation and so why it is desirable for Transpower to consider them. Following these sections, the efficiency gains from the additional Code changes are discussed.

Additional component 1: Staged commissioning

10.26 Under the proposed guidelines, Transpower would be required to consider whether to include in the TPM a method to clarify that, when an asset meets the definition of connection asset during staged commissioning, it is charged for on that basis, even though, when commission is complete, the asset will provide interconnected grid services.

10.27 Under the current TPM a customer that benefits from an asset pays the full cost of the asset if it is a connection asset but very little of the cost if it is an interconnection asset. Transmission customers therefore have strong incentives to ensure that any asset they benefit from is classified as an interconnection asset.

10.28 While the incentives to reclassify assets in this manner will be reduced by the introduction of the area-of-benefit charge, they will not be eliminated.

10.29 Clarifying the treatment of assets during staged commissioning therefore has the potential to reduce unproductive activity and disputes, reducing the cost of investment and so increasing efficiency.

Additional component 2: charging for assets when their classification changes due to new investments

10.30 Under the proposed guidelines, Transpower would be required to consider whether to include in the TPM a method for charging for assets when their classification changes due to new investments by a third party.

10.31 This is because the relevant definitions in the TPM rely on the physical and electrical configuration of assets, so an investment which changes these could lead to an asset that effectively delivers connection services being reclassified as an interconnected grid asset, and the costs would be recovered through charges on interconnected grid assets.

10.32 The Authority considers that this situation does not promote efficient investment to the extent that the costs of connection and interconnected grid assets are recovered differently.

10.33 The Authority therefore considers the guidelines should require Transpower to provide for connection assets to continue to be categorised as such when the assets are connected by a new line, and the assets continue to provide connection services through connecting customers to the grid.

Additional component 3: Charging for operating and maintenance on an actual-cost basis

10.34 Under the proposed guidelines, Transpower would be required to consider whether to include in the TPM a method of allocating operating and maintenance costs for connection and area-of-benefit assets to the parties that pay charges in relation to those assets on an actual-cost basis.

10.35 The advantage of allocating these costs directly is that it will encourage major beneficiaries of an asset:

(a) to scrutinise Transpower's operating and maintenance expenditure on the asset

(b) to take account of the impact of their own actions on the operating and maintenance costs of the asset.

10.36 These benefits are greatest when there are a few beneficiaries of the asset in question, and diminish as the number of beneficiaries increases, because the operating and maintenance costs are in effect currently socialised across all beneficiaries of the asset.

10.37 A potential disadvantage is that, with the area-of-benefit charge for new assets being calculated at replacement cost, it could encourage beneficiaries to seek premature replacement of the asset.

10.38 However, this potential disadvantage is avoided through the Authority's proposal to ensure that the area-of-benefit charge is based on the full cost (no more and no less) of each new asset, as described in chapter 7. As a result, users will only have the incentive to seek a replacement asset if its total annualised cost (including the capital cost less any recovery on the old asset) is less than the operating and maintenance costs of the existing asset, which is efficient.

Additional component 4: LRMC charge

10.39 Under the proposed guidelines, Transpower would be required to consider introducing an LRMC charge.

10.40 In principle, as discussed in chapter 5, nodal pricing in the spot market should signal reasonably well the marginal benefit of new investments in the interconnected grid. However, in practice nodal pricing may provide insufficient price signals, such as when additional use of an asset prompts the need for new investment to ensure grid reliability rather than to relieve congestion.

10.41 In that case an LRMC charge can add to efficiency in investment. It does this by signalling to users the opportunity cost of their use in accelerating investment in a new asset. It therefore rations their demand for new investment until the benefit they derive from it exceeds the cost of the investment. This encourages users to behave as they would if they faced fully effective nodal pricing signals and so can add to efficiency

10.42 In addition, there may be a case for introducing a more forward-looking charge that signals ahead of the need for investment if that would also help to efficiently deter investment.

Additional component 5: kvar charge

10.43 Under the proposed guidelines, Transpower would be required to consider introducing a kvar charge.

10.44 A kvar charge would signal to transmission users the cost of installing equipment to correct power factors due to over-use of reactive power by transmission customers.

10.45 If Transpower considers there were net benefits from introducing a kvar charge, and so introduced a kvar charge, this would encourage efficient investment as it would encourage transmission users to draw reactive power only where it is efficient to do so, or otherwise invest in equipment to manage their reactive power use when they can do so more cheaply than Transpower. This will promote more efficient investment in static reactive power equipment in the grid and by consumers of reactive power.

Additional Code change 1: Power factor of 0.95 lagging

10.46 The Authority proposes to change the Connection Code to specify that the minimum power factor for each region is 0.95 lagging. Codifying this should ensure transmission users have certainty when making investment decisions about the level of power factor they will face in future, and so improve efficiency.

Additional Code change 2: Loss and constraint excess

10.47 The Authority proposes to change the Code to codify the treatment of LCE received by the grid owner and the future treatment of FTR auction proceeds. Codifying current and future practice should ensure regulatory uncertainty does not arise in regard to the way in which these sources of revenue are allocated to offset the cost of transmission services. By reducing investor uncertainty, this should assist with promoting efficient investment.

Facilitation of efficient operation of the electricity industry

10.48 As is discussed above, nodal spot market prices, possibly supplemented by LRMC charges, promote efficient use of the grid. The Authority's proposal facilitates efficient operation of the electricity industry in the following ways:

(a) It introduces an area-of-benefit charge, as described in chapter 7. The area-of-benefit charge has been designed to minimise its impact on grid use, and so promote efficient operation of the electricity market. In particular, the intention is to apply the charge on the basis of forecast benefits, which grid users cannot alter by altering their grid use. The area-of-benefit charge should therefore promote more efficient operation of the electricity industry than the current TPM.

(b) It uses replacement costs for new assets (as opposed to the earlier proposal of depreciated replacement cost). This will ensure that the charge for an investment is better matched over time to the services that investment provides.

(c) Where an asset in a high value investment has substantially more capacity than is necessary to permanently meet its users' collective needs, the value of the asset will be optimised (but generally after an initial period for assets in new high value investments). This reduces the area-of-benefit charge for optimised assets, reducing any distortions, such as inefficient exit, arising from the area-of-benefit charge.

(d) If Transpower decides to allocate operating and maintenance costs on an actual cost basis, this will encourage customers to monitor Transpower's operating and maintenance activity, and to take into account the impact of their own actions on those costs. Both impacts on behaviour should promote more efficient operation of the electricity industry.

(e) The residual charge is designed to recover the remainder of Transpower's revenue in a way that minimises its impact on the use of the interconnected grid. In particular, the charge is allocated based on historic physical capacity, and so changes in grid use will have little impact on the residual charge to be paid. Compared to the status quo TPM, the residual charge should promote more efficient operation of the electricity industry.

(f) The proposed revisions to the prudent discount policy should promote ongoing use of the grid when that is efficient. However, extending the prudent discount policy increases the risk that it promotes activity to access the PDP when that is not justified. Such activity is inefficient. The proposed PDP seeks to minimise this inefficiency by having criteria for the application of the policy.

(g) If Transpower decides to introduce an LRMC charge, it will encourage beneficiaries to use the interconnected grid only when they are prepared to collectively pay for any new investment brought about by their grid use. That is, they will use the interconnected grid in ways that promote efficient investment.

(h) The kvar charge, if introduced, will ensure that parties drawing reactive power will invest in and operate their equipment so that they only draw reactive power from the grid to the extent that the benefits exceed the costs, including the costs to them of the kvar charge. In other words, they will use reactive power only when it is efficient overall for them to do so.

How the proposal contributes to efficiency through promoting durability

10.49 The Authority is of the view that the following aspects of its proposal will make the regulatory arrangements for the industry, including in particular the TPM, more durable:

(a) The proposed TPM is more cost-reflective than the current TPM and the proposed charges will relate to the services delivered. That is, those who benefit from a particular grid service would pay for that service. This is likely to be perceived as fair, limiting opposition to the charges and reducing the likelihood they seek fundamental changes to the TPM.

(b) Those who will benefit from potential new investments have an incentive to support those investments, knowing the charges they will have to pay, to ensure that the investment proceeds, making it less likely that they will subsequently oppose payment and seek fundamental changes to the TPM.

(c) Those who do not benefit from potential new investment would not have to pay the area-of-benefit charge associated with it, making them indifferent to whether the investment proceeds or not. Thus, unnecessary disputes that would be caused by them having to pay for those investments are avoided, removing their incentive to seek fundamental changes to the TPM.

(d) The area-of-benefit charges can be adjusted if circumstances materially change. It ensures that those who would benefit from or use the asset in future will pay the area-of-benefit charge then, enhancing cost reflectivity, and so sustaining the benefits outlined above.

(e) After an asset has been in use for a period, the replacement cost on which area-of-benefit charges are levied can be optimised to take account of substantial reductions in use of the asset. This means that those who continue to benefit from the asset do not have to pay higher charges simply because others have stopped using the asset. If they did, it would likely be perceived as unfair and so prompt calls for changes to the TPM.

(f) The LRMC charge, if adopted, would signal the cost of new investment before it is undertaken, and thus smooth the charges that transmission customers have to pay, reducing the chance of price shocks (which might prompt opposition to the change in charge).

(g) Several aspects of the proposal clarify how the regulatory regime will apply in future, thus reducing uncertainty—for example, the proposed change to the Code to clarify the use of the LCE.

10.50 In other words, a new TPM prepared to give effect to the proposed guidelines is less likely to result in disputes, in calls to fundamentally change the TPM because of various perceived or actual problems with it, and in fewer unproductive changes to the TPM. This would add to efficiency directly, since all of the activities outlined above have real resource costs. It would also add to efficiency indirectly, since the greater certainty about the future shape of the TPM would reduce uncertainty for investors, which would lead to more efficient investment in the grid, in substitutes for the grid and in related investment.

Assessment of the proposal against overall efficiency—negative effects

10.51 This section outlines the negative effects of the proposal on efficiency. If implemented, the proposal would impose implementation and operational costs on Transpower and/or another party that was charged with undertaking these activities. By far the most significant costs would be those associated with designing, implementing and operating the area-of-benefit component of the proposal. As chapter 8 shows, the Authority's proposal shows substantial positive benefits under any realistic estimate of these costs.

10.52 Some submitters on the TPM options working paper submitted that an area-of-benefit charge[254] could be contentious because it was not entirely objective. Likewise, other parties were concerned that an area-of-benefit charge may not be durable because parties would strongly disagree about whether they were the beneficiaries of an investment or not, and hence whether they should be charged, which would result in costly lobbying and associated activities.

10.53 The Authority recognises that there is no perfect area-of-benefit charge, and that there will be some level of contentiousness associated with the area-of-benefit application and potential for lobbying and disputes. However, in the Authority's judgement an area-of-benefit charge is much less likely to be contentious and non-durable than the current charging regime because an area-of-benefit charge results in more cost-reflective and service-based charges. It will be more difficult and unsustainable to argue against being charged for a transmission asset from which a party benefits. Moreover, disputes over the area-of-benefit charge are

[254] Meridian (p.2,5), Fonterra (p.5), Marlborough Lines (p.8).

more likely to be focused on discovering more accurate and robust estimates of key parameters rather than focused on advocating for an entirely different pricing approach. Such disputes are less likely to have an adverse impact on investor certainty.

10.54 Furthermore, the Authority has proposed, for high value investments, a more granular approach for determining the area-of-benefit charge than was proposed in the TPM options working paper, which has increased the objectivity, accuracy and efficiency of this proposed component.

10.55 The Authority recognises that applying an area-of-benefit charge to some existing post-2004 investments plus Pole 2, might be thought to encourage parties to avoid using those investments, relative to other investments. However, in the Authority's judgement this incentive is likely to be weak or non-existent in most cases and unlikely to result in significant inefficiencies. The Authority holds this view because:

(a) Transmission charges are only one factor that determines a parties' use of the interconnected grid. Other factors such as the location of a customer, which in turn depends on the source of its inputs and destination of its outputs, are often more relevant.

(b) The Authority has proposed an ex-ante determination of benefits which minimises the ability of customers to change their behaviour to avoid the area-of-benefit charge. As a result, most transmission customers will have a very limited ability to avoid the area-of-benefit charge.

(c) The area-of-benefit charge would be calculated according to parties' private benefits, and so avoiding use of the asset would reduce their private benefit.

(d) Over time, as existing assets that are covered by the residual charge are refurbished or replaced they will be covered by the area-of-benefit charge. Thus the residual charge will diminish over times in real terms, so any inefficiency caused by the residual charge will diminish over time

10.56 On a related matter - the potential inefficiencies of changing the charging regime for existing assets - the Authority's 2013 sunk cost working paper showed that there is no sound economic reason why new charges should not be imposed on existing assets. The relevant consideration was where a cost was fixed, and that the "sunk" nature of an asset had no relevance to pricing. For the reasons noted in chapter 5, the Authority considers that there are good reasons to expect charging for historical assets to improve the durability and so the efficiency of the proposal.

10.57 A potential negative aspect of the proposed residual charge is it would create an incentive for users to alter the measure of their capacity in order to reduce the amount of the residual charge they have to pay. Some such inefficiency is inevitable in any real-world charge, because neither the Authority nor Transpower can obtain the information in practice to impose a distortion-free residual charge. However, because the Authority is proposing to used lagged historical capacity, the size of the inefficiency is likely to be small.

10.58 The major potential inefficiencies associated with the additional components are the costs associated with implementing them and operating them. This is most relevant to the LRMC charge. The LRMC charge would require the identification of areas where an LRMC charge would have net benefits, determination of how the LRMC charge would be applied, and the application of the charge. However, as chapter 6 demonstrates, the potential gains of efficiently deferring investment can be very large. Furthermore, each of the additional components will only be implemented if they are consistent with the Authoriy's statutory objective.

10.59 Over the course of the Authority's TPM review, a number of submitters have expressed their view that the imposition of a new charging regime on existing assets, such as proposed by the area-of-benefit charge and the residual charge, creates regulatory uncertainty which in turn undermines confidence to invest in the sector and reduces dynamic efficiency.[255] The Authority recognises that changing regulatory settings, including those associated with the imposition of charges, after parties have made decisions and investments, can cause regulatory uncertainty and reduce dynamic efficiency. However, the Authority is of the view that making changes that support its statutory objective, which is to, inter alia, promote efficiency for the long-term benefits of consumers, will create regulatory certainty. In addition,the Authority's judgement is that imposing new charges on existing transmission assets is very unlikely to result in dynamic efficiency losses that exceed the benefits of the proposal because:

(a) the charges are inherently more efficient than the existing charges as evidenced by the CBA

(b) the current TPM has been contentious since it was introduced in 2008, which has created uncertainty about the durability of the charging regime

Impact on reliable supply

10.60 The Authority has interpreted the reliable supply limb of the statutory objective as meaning the efficient level of reliable supply. In particular, the Authority has interpreted the reliable supply limb as "exercising its functions in ways that 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."

10.61 This means that reliable supply relates to both efficient use and efficient investment. The Authority considers that the proposal would help better promote efficient use and investment, for the reasons outlined above. To avoid unnecessarily repeating the discussion above, in summary, the most relevant factors that will lead to an improvement in reliability are:

(a) The area-of-benefit charge will increase the quality of transmission investment decisions. It will make it less likely that decisions are made to proceed with an investment in the interconnected grid when it is not justified as well as to not proceed with investments that are justified. It also improves the chances of avoiding investments in the interconnected grid that are more expensive than they need to be.

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[255] For example, Trustpower (p,13), West Coast Electric Power Trust (p.3) and Refining NZ (p.2) submissions on the options working paper.

(b) Future investment decisions in the interconnected grid will inherently be more efficient than currently because the better price signals provided by the area-of-benefit charge will incentivise more efficient use of the interconnected grid. This in turn will incentivise better transmission investment decisions.

(c) As noted by Meridian, "the area-of-benefit charge has the advantage of being applicable for reliability investments"[256] This is because the area-of-benefit charge - depending on the methodology used to identify beneficiaries - is capable of identifying those benefiting from reliability investments and charging them accordingly, which will help promote an efficient level of reliability.

10.62 The above factors mean that the interconnected grid is likely to be built and operated at a level that is more consistent with achieving efficient levels of reliability. The current TPM, as discussed in the problem definition section of this paper, incentivises Transpower to build more transmission assets than would be the case under a more service-based and cost-reflective regime. The area-of-benefit charge is more service-based and cost-reflective than the current interconnection and HVDC charges so it is expected to result, if implemented, in more efficient reliability for the interconnected grid.

10.63 The proposal, if implemented, would substantially reduce ACOT payments to distributed generators. The Authority does not expect that this will adversely affect reliability because, as proposed in the separate DGPP consultation paper, Transpower will fund distributed generation that genuinely avoids transmission costs and provides the benefits that would otherwise need to be provided by transmission (including reliability benefits).

Impact on competition

10.64 The proposal would set charges for transmission services on a more consistent and cost-reflective basis. As a result, generators would have to take into account their impact on transmission costs in making their own decisions on investments in generation, including in particular the location of that investment. This would mean that generation customers who currently bear more than the costs their use of the interconnected grid warrants would not be artificially disadvantaged compared to those who bear less. That is, competition between them would lead to more efficient generation choices.

10.65 Similar considerations apply to load customers (including load customers of distributors).

10.66 In short, competition between generation customers and competition between load customers would be more efficient because it is more likely to lead to socially productive outcomes.

10.67 In addition, because the TPM would be more cost-reflective, customers would gain less from seeking to have investments beneficial to them paid for by others.

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[256] Meridian, submission on options working paper, page 20.

As a result, as Baumol describes,[257] entrepreneurial efforts are likely to be focussed on socially productive activities, enhancing socially productive competition.

10.68 The proposal, if implemented, would substantially reduce ACOT payments to distributed generators. Although this would reduce the ability of inefficient (ie, “subsidised”) distributed generation to compete against transmission services, competition from “subsidised” competitors is typically socially harmful. As proposed in the separate DGPP consultation paper, Transpower would fund distributed generation that genuinely avoids transmission costs and provides benefits otherwise provided by transmission. These efficient (ie, “unsubsidised”) sources of distributed generation would be able to compete against transmission services. There is a risk that reducing ACOT payments may affect the level of investment in generation, and thus, reduce generation competition, at least in some regions. However, this does not justify ongoing payments to parties for generation that enables avoidance of transmission charges if this does not also avoid transmission costs.

Summary of assessment of the proposal against the limbs of the statutory objective

10.69 In summary, the Authority believes the proposal would promote all three limbs of the Authority’s statutory objective and provide long-term benefits to consumers. Only in relation to the efficiency limb has the Authority identified some genuine and material dis-benefits. However, as discussed above, and as shown by the CBA, the Authority judges the net benefits to be large and positive under any reasonable assumption about these dis-benefits.

Trade-offs between efficient operation, reliable supply, and competition

10.70 Although the Authority’s proposed guidelines are targeting efficient operation of the electricity industry, and this may affect competition and reliable supply, the proposal supports the promotion of an efficient level of reliability and competition, consistent with the Authority’s interpretation of its statutory objective. Further, as the previous sections note, the proposal has the potential to enhance both reliability and competition, as well as efficient operation. This combination would promote the long-term benefit of consumers.

Assessment of alternatives

10.71 The Authority has identified alternative options for pursuing the objectives sought from the proposal. These are discussed in detail in chapter 9. Table 6 below provides a summary assessment of these alternatives against the three limbs of the statutory objective. The first column identifies improvements compared with the status quo TPM. The second column then compares those improvements with the improvements that the proposal is expected to realise.

[257] *Entrepreneurship: Productive, Unproductive, and Destructive*, William J. Baumol, Journal of Political Economy 1990.

Table 6: Assessment of alternatives against the three limbs of the statutory objective

Alternative 1: Deeper connection charge

Efficiency	
Compared to Status Quo	***Compared to the Authority's proposal***
The deeper connection charge is broadly service-based and cost-reflective compared with the current TPM, and therefore it is likely to better promote allocative, productive and dynamic efficiency.	Since the deeper connection methodology is based on flows rather than benefits, customers may face deeper connection charges that exceed the benefit they will receive, limiting the allocative, productive and dynamic efficiency gains. The incorporation of optimisation may limit this potential issue.
Being broadly service-based and cost-reflective, the alternative is expected to support the discovery of the need for efficient transmission investment through the investment approval process.	Because the deeper connection charge would only partially recover the costs of most assets that would be subject to it, with remaining costs recovered through the residual charge, it is unlikely to be as effective at promoting efficient investment as the area-of-benefit charge.
The alternative is likely to be durable because there would be a correlation between the customers that receive services from an asset and the customers that pay for that asset.	Since the deeper connection charge would be calculated according to use, it may result in some distortions to behaviour designed to avoid the charge.
Reliability	
Compared to Status Quo	***Compared to the Authority's proposal***
Being broadly service-based and cost-reflective, the deeper connection charge will facilitate better investment decisions relating to reliability investments.	The deeper connection charge may not effectively capture reliability events which typically occur irregularly, unless the flow-trace modelling covers a high number of years. This may limit the extent to which the deeper connection charge, and therefore this option, promotes an efficient level of reliability.
Competition	
Compared to Status Quo	***Compared to the Authority's proposal***
Being service-based and cost-reflective, the deeper connection	The deeper connection charge may result in parties such as generators

charge will promote competition between transmission services and alternatives such as gas transmission.	avoiding transmission assets where generation rather than load incurs deeper connection charges, potentially reducing the number of generators, and therefore generation competition, in some regions.
Being a market-like charge, the deeper connection charge will promote contractual arrangements that will provide competition to transmission services funded through the TPM.	

Alternative 2: Alternatives under the existing Guidelines

Efficiency	
Compared to Status Quo	***Compared to the Authority's proposal***
A revised connection charge that extends connection assets deeper into the grid could be more cost-reflective that the current TPM.	The existing guidelines limit service-based and cost-reflective charging deep within the grid where a deeper connection charge might not apply.
	The existing guidelines limit service-based and cost-reflective charging by limiting HVDC charges to South Island generators and by limiting interconnection charges to loads.
	Limiting the extent of serviced-based and cost-reflective charging may promote reduced scrutiny of proposed investmentsand inefficient transmission investment, and durability problems with the current TPM may endure.
Reliability	
Compared to Status Quo	***Compared to the Authority's proposal***
	The continuation of a postage stamp charge on interconnection assets is likely to result in inefficient reliability investments being proposed to the Commerce Commission. This is inconsistent with the promotion of an efficient level of reliability.

Competition	
Compared to Status Quo	***Compared to the Authority's proposal***
	The limitation to service-based and cost-reflective charging under this alternative will promote an inefficient preference for transmission solutions over alternatives such as gas transmission, generation and demand response.

Alternative 3: Tilted postage stamp

Efficiency	
Compared to Status Quo	***Compared to the Authority's proposal***
Improves efficiency	***Reduces efficiency***
The LRMC-like signal that this alternative provides would better promote efficient transmission investment than the current TPM.	The tilted postage stamp charge would be less service-based and cost-reflective than the Authority's proposal because charges would not necessarily apply to the specific parties that benefit from transmission services and would less accurately promote an efficient level of investment than the more targeted charges under the Authority's proposal (notably the area-of-benefit, LRMC and kvar charges).
The charge would be somewhat more service-based and cost-reflective than under the current TPM because charges would reflect expectations around future investments.	The LRMC-based option for tilted postage stamp charge is heavily dependent on the accuracy of future transmission investment forecasts and the extent to which the application of the charge reflected actual underlying drivers of investment.
The alternative would be more durable than the current TPM because charges would be more reflective of the incremental costs of providing parties with transmission services.	Because it is not substantially serviced based and cost reflective, the alternative would continue many of the durability problems of the current TPM

Reliability	
Compared to Status Quo	***Compared to the Authority's proposal***
Improves reliability	***Reduces reliability***
The LRMC-like signal should signal the cost of reliability investments and provide a locational signal, subject to a requirement to make assumptions about future transmission investments.	
Competition	
Compared to Status Quo	***Compared to the Authority's proposal***
Improves competition	***Reduces competition***
	The less granular methodology will be less service-based and less cost-reflective than the proposal, thus limiting efficient choices between transmission and alternatives such as gas transmission, generation and demand response.

Alternative 4: SPD-based charge

Efficiency	
Compared to Status Quo	***Compared to the Authority's proposal***
The SPD-based charge should be service-based and better promote efficient transmission investment as charges would better reflect the benefit parties received from transmission investments.	Being an ex-post charge, the SPD charge could distort bids and offers in the wholesale market, negatively affecting the efficiency of the wholesale market.
The alternative is likely to be more durable than the current TPM because the methodology is service-based and cost-reflective, and also objective in calculating benefits.	
Reliability	
Compared to Status Quo	***Compared to the Authority's proposal***
	The charge is not likely to provide an efficient signal around the cost of

	reliability investments because modelling covers an insufficient time period to properly account for reliability benefits which can occur irregularly and towards the last few years of an asset's economic life.
	Generators may be incentivised to avoid injecting into the grid during times of high demand.
Competition	
Compared to Status Quo	***Compared to the Authority's proposal***
Improves competition	***Reduces competition***
The highly granular methodology is service-based and cost-reflective (with the possible exception of reliability investments), thus it promotes efficient choices between transmission and alternatives such as gas transmission, generation and demand response.	

Alternative 5: Broad-based, low rate charge for each island or four transmission pricing regions combined with a broadly levied HVDC charge

Efficiency	
Compared to Status Quo	***Compared to the Authority's proposal***
Given its locational signal, the broad-based, low rate charge would be somewhat more service-based and cost-reflective than the current interconnection and HVDC charges.	The broad-based, low rate charge could only be poorly service-based and cost-reflective relative to the Authority's proposal, as the postage stamp nature of the charges would inevitably mean a significant portion of charges that customers pay would be for investments from which they would not benefit.
Reliability	
Compared to Status Quo	***Compared to the Authority's proposal***
	The less granular methodology will provide less scrutiny of and less incentive for efficient reliability investments to be proposed to the Commerce Commission.

Competition	
Compared to Status Quo	***Compared to the Authority's proposal***
	The less granular methodology will be less service-based and less cost-reflective than the proposal, thus limiting efficient choices between transmission and alternatives such as gas transmission, generation and demand response.

Conclusion

10.72 As is evident from the analysis above, the Authority considers that its proposal promotes the Authority's statutory objective. The proposal outperforms the current TPM and also outperforms the alternatives it has investigated.

10.73 The Authority's proposal is primarily targeted at the efficiency limb of the statutory objective. This is because the proposal provides for service-based and cost-reflective charges that promote efficient investment in and operation of the electricity industry. The Authority considers that there is a trade-off between a high level of granularity in providing service-based and cost-reflective charges and the cost of developing and administering the methodology. There is also a trade-off between dynamic efficiency, which requires service-based and cost-reflective charges, and operational efficiency where charges need to avoid distorting operational decisions. The proposal provides for service-based and cost-reflective charges, which promote efficient investment and operation while it seeks to minimise inefficient avoidance through ex-ante charges that are aligned to parties' private benefits and a historical-physical-capacity-based residual charge, both of which promote efficient operation.

10.74 The Authority considers the proposal also promotes the reliability and competition limbs of the Authority's objective. The proposal promotes reliability principally because it charges the beneficiaries of reliability investments, thus promoting efficient levels of reliability, as parties will only seek a level of reliability they are willing to pay for.

10.75 The proposal promotes competition because service-based and cost-reflective charges promote efficient choices between transmission and transmission alternatives such as gas transmission, demand response and distributed generation.

10.76 The Authority has not identified any significant problems with its proposal in relation to reliability and competition. While the Authority expects that some parties will consider that the proposal's effect on ACOT payments will reduce both reliability and competition in the generation market, the Authority's view is that Transpower would have incentives to contract for an efficient level of distributed generation services to the extent that they reduce transmission costs. The Authority is proposing in its DGPP consultation paper that Transpower funds distributed generation that actually avoids transmission costs. Thus, a form of ACOT will likely continue, to the extent that ACOT payments are efficient.

11 Evaluation of the proposal against the Authority's Code amendment principles

11.1 This section evaluates the proposal against the Authority's Code amendment principles.

Principle 1 – Lawful

11.2 The proposal is lawful.

Principle 2 – Provides clearly identified efficiency gains or market or regulatory failure

11.3 The proposal (ie, to issue new TPM guidelines and implement a TPM that gives effect to those guidelines) will improve efficiency, as set out in chapters 8 and 10 of this paper.

Principle 3 – Net benefits are quantified

11.4 The cost-benefit analysis of the proposal is summarised in chapter 8 and Oakley Greenwood's full analysis is provided in Appendix C. Oakley Greenwood shows that under all scenarios the quantified benefits exceed the quantified costs.

11.5 However, Oakley Greenwood do not quantify all of the benefits from the proposal. Instead, they discuss a range of other benefits they were unable to quantify. The Authority is of the view that the unquantified benefits are likely to be substantial, and has provided its reasons for this view in chapter 8.

Tiebreaker 1: Principles 4-8

11.6 The quantified part of the OGW CBA shows that the Authority's proposal has a net benefit of $213 million, $5 million more than that of the deeper connection option. This difference is small. However, the Authority considers that, because the OGW CBA also identifies non-quantified benefits of the Authority's proposal relative to the deeper connection option, it is not necessary to apply the tiebreaker in the Authority's Consultation Charter. In the Authority's judgement, those benefits are substantial and mean that the Authority's proposal has a substantial positive net benefit compared with the deeper connection option.

11.7 Nevertheless, in this section the Authority assesses its proposal against principles 4-8 as if it had to apply the tiebreaker.

Principle 4 – Preference for small-scale "trial and error" options

11.8 This principle does not provide a basis on which to discriminate between the Authority's proposal and the deeper connection option.

Principle 5 – Preference for greater competition

11.9 The Authority is of the view that its proposal is more likely to promote competition in a manner consistent with its statutory objective, because it charges transmission customers in accordance with the benefit they receive. In contrast, the design of the deeper connection option means that a business might gain a competitive advantage, not because it is more efficient, but because it is charged less for grid use than an otherwise similar competitor.

Principle 6 –Preference for market solutions

11.10 The Authority was previously of the view that the deeper connection option is somewhat more market like than its proposal. This is because the deeper connection charge applies only where the number of users of an investment is limited, so in theory could come to a voluntary agreement to contract for the investment. However, the Authority has since made changes to both its proposal and the deeper connection option. In particular, it has had to make changes to the deeper connection option to avoid inefficient behaviour. In addition, as Chapter 5 notes, in a workably competitive market, the price a buyer pays for a product will always exceed the benefit the buyer expects to get from it. As a consequence of these changes, it is now the view of the Authority that its proposal is more market like. However, this advantage is relatively small because both are likely to remain administrative solutions.

Principle 7 – Preference for flexibility to allow innovation

11.11 Both the Authority's proposal and the deeper connection option have been designed to charge grid users for the cost of the transmission assets they use and allow them operational freedom to use the grid as they see fit. In addition, both have additional components which give Transpower flexibility as to whether and how to apply them. However, the Authority's proposal is likely to result in activity that has a lower economic cost and so is more consistent with the Authority's statutory objective, because the deeper connection option is likely to result in charges for each asset being less well aligned to the benefits grid users get from it, compared with the Authority's proposal.

Principle 8 – Preference for non-prescriptive options

11.12 Both the Authority's proposal and the deeper connection option have been designed to charge grid users for the cost of the transmission assets they use and allow them operational freedom to use the grid as they see fit. They are both therefore non-prescriptive. Both proposals also allow Transpower flexibility about whether to adopt the 5 additional components. In addition, the Authority's proposal allows Transpower to choose the best method of determining who benefits from an investment, whereas the deeper connection option is prescriptive. Potentially, therefore, the Authority's proposal allows Transpower to adopt a method of determining benefits which can adapt as technology evolves. Therefore the Authority's proposal is preferred under Principle 8.

Conclusion: tiebreaker 1: principles 4-8

11.13 As is noted above, the Authority is of the view that it does not need to consider tiebreaker 1, because, taking account both the quantitative and qualitative aspects of the OGW CBA, the Authority's proposal is clearly preferable. However, if it were to apply tiebreaker 1, the Authority's judgement is that overall principles 4 to 8 also favour the Authority's proposal.

Conclusion

11.14 Overall, the Authority considers that its proposal is consistent with the Authority's statutory objective and the Authority's Code amendment principles.

12 Proposed process for development and approval of the TPM

12.1 As required under clause 12.81 of the Code, this chapter sets out a draft process for the development and approval of the TPM.

12.2 If the Authority publishes its final process and guidelines under clause 12.83 of the Code, the Authority will request that Transpower submit a proposed TPM (clause 12.88 of the Code).

12.3 Clause 12.88 of the Code requires Transpower to submit a proposed TPM within 90 days, or such longer period as the Authority may allow. The Authority anticipates that 90 days will not be long enough for Transpower to develop a new TPM. The Authority is open to allowing a longer timeframe, and will consult with Transpower further on this point.

12.4 Having reflected on the process followed by Transpower for its operational review, the Authority considers that it would be appropriate for Transpower to adopt a consultation process in its development of the TPM. Transpower should decide the extent and form of that consultation process, including whether to invite cross submissions.

12.5 The Authority is aiming to have the new TPM in place for the April 2019 pricing year. The Authority proposes that Transpower and the Authority work together to develop a project plan for the development of the TPM aimed at meeting the April 2019 timeframe. The project plan should include key milestones and timeframes for the development of the TPM. It should also include a description of Transpower's planned consultation process.

12.6 When the Electricity Commission proposed a process for the development of the current TPM,[258] Transpower was requested to propose how costs related to revenue that was not subject to regulatory review by the Electricity Commission would be determined and allocated.[259] The Electricity Commission's rationale for this was that the TPM is based on asset costs, and so the determination and allocation of costs associated with assets developed without regulatory review may be of interest to stakeholders. Investment approval is now the responsibility of the Commerce Commission and Transpower is subject to Individual Price-Quality Regulation under Part 4 of the Commerce Act. The Authority therefore considers that it is not necessary or appropriate to impose a similar requirement on Transpower to that included by the Electricity Commission in 2004.

12.7 In its proposed TPM submitted under clause 12.88 of the Code, Transpower may submit multiple options to meet any of the guidelines, if Transpower considers that doing so is likely to result in better decision-making.

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[258] The delay between the publication of guidelines was due to a challenge to the guidelines. The challenge resulted in revised guidelines. However, the process was not reconsidered.

[259] Electricity Commission: *Process for Transpower to develop the Transmission Pricing Methodology: Consultation Paper,* 22 December 2004.

12.8 Once Transpower submits its TPM under clause 12.88 of the Code, the Authority will follow the process provided for in clauses 12.91 to 12.94 of the Code. That process includes a consultation under clause 12.92 of the Code and section 39 of the Act. The Authority will allow at least 6 weeks for that consultation.

Appendix A TPM guidelines for development of Transmission Pricing Methodology

TPM guidelines for development of the Transmission Pricing Methodology

Published under clause 12.83(b) of the Electricity Industry Participation Code 2010 on [insert date]

Introduction

1. These guidelines for the development of the transmission pricing methodology (**TPM**) are published by the Electricity Authority (**Authority**) under clause 12.83(b) of the Electricity Industry Participation Code 2010 (**Code**).

Interpretation

2. In these guidelines, the following terms have the meaning given to them in the Transpower Capital Expenditure Input Methodology Determination [2012] NZCC 2, including each amendment to that determination, in force on the date of these guidelines:

   (a) base capex:

   (b) capital expenditure:

   (c) commissioned:

   (d) completion date:

   (e) major capex:

   (f) major capex project:

   (g) major capex proposal:

   (h) non-transmission solution:

   (i) programme:

   (j) project.

3. Unless the context otherwise requires, any other term that is defined in Part 1 of the Code and used but not defined in these guidelines has the same meaning as in Part 1 of the Code.

General

4. To be consistent with the Authority's statutory objective specified in section 15 of the Electricity Industry Act 2010 as required by clause 12.89(1)(b) of the Code, the TPM must be directed at—

   (a) facilitating efficient investment in the electricity industry by providing incentives for the right investments to occur at the right time and in the right place. Those investments may be in the transmission grid, generation (including distributed generation), distribution networks or the demand-side; and

   (b) facilitating the efficient operation of the transmission grid, generation (including distributed generation), distribution networks and demand-side management. This means providing incentives so that the day to day operation of transmission, generation, distribution, and demand-side management involves an efficient trade-off between reliability and cost.

Connection charge

5. Subject to clauses 43 to 47 of these guidelines, the TPM must—

   (a) include a definition of connection asset that corresponds to the definition of connection asset in the TPM in force on the date of these guidelines; and

   (b) charge for connection assets on the same basis, and with the same effect, as under the TPM in force on the date of these guidelines.

Area-of-benefit charge

6. The TPM must include an area-of-benefit charge that recovers the full cost of each asset (excluding any connection asset) that is included in an eligible investment.

7. An eligible investment is any of the following:

   (a) a project or programme of base capex or major capex, that is commissioned on or after the date of these guidelines; and

   (b) the following investments:

      (i) the North Island Grid Upgrade Project, approved by the Electricity Commission on 5 July 2007; and

      (ii) the Upper South Island Dynamic Reactive Support Project, approved by the Electricity Commission on 25 July 2007; and

      (iii) the Otahuhu Substation Diversity Proposal, approved by the Electricity Commission on 30 August 2007; and

      (iv) the HVDC Project, approved by the Electricity Commission on 25 September 2008; and

(v) the Wairakei Ring Project, approved by the Electricity Commission on 20 February 2009; and

(vi) the North Auckland and Northland Project, approved by the Electricity Commission on 30 April 2009; and

(vii) the Upper North Island Dynamic Reactive Support Project, approved by the Electricity Commission on 5 July 2010; and

(viii) the Lower South Island Renewables Project, approved by the Electricity Commission on 9 August 2010; and

(ix) the Lower South Island Reliability Project, approved by the Electricity Commission on 6 September 2010; and

(x) the Bunnythorpe-Haywards Reconductoring Project, approved by the Commerce Commission on 9 May 2014; and

(c) Pole 2 of the HVDC link; and

(d) to the extent not covered by paragraphs (a) to (c), the cost of any payments made by Transpower in respect of a non-transmission solution.

8. The TPM must include—

(a) a standard method to apply to each eligible investment valued at $5 million or more at the time the investment is commissioned or at the completion date, as the case may be (**high value investment**); and

(b) a simplified method to apply to each eligible investment valued at less than $5 million at the time that the investment is commissioned or at the completion date, as the case may be (**low value investment**); and

9. Each of the methods described in clause 8 must—

(a) for each eligible investment, identify the areas-of-benefit (in the case of the standard method) or the main areas-of-benefit (in the case of the simplified method). 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; and

(b) apportion charges to each area-of-benefit based on the aggregate expected positive net benefit to the designated transmission customers to which positive net benefits are expected to accrue in that area-of-benefit; and

(c) allocate charges to generation designated transmission customers and load designated transmission customers so that each group is allocated charges that correspond to the proportion of the aggregate positive net benefits that the group is expected to receive from the eligible investment; and

(d) apportion the area-of-benefit charge between eligible investments, if a project or programme provides for replacement or refurbishment of assets contained in 2 or more of those eligible investments.

10. The standard method must—

(a) to the extent practicable, provide for charges to be allocated to designated transmission customers in an area-of-benefit so that each customer is allocated the proportion of the charges that corresponds to the proportion of the aggregate positive net benefits that it is expected to receive from the eligible investment in that area-of-benefit; and

(b) to the extent that the method in paragraph (a) is not practicable, provide for—

(i) charges to be allocated to each load designated transmission customer in the area-of-benefit on the basis of each customer's physical capacity; and

(ii) charges to be allocated to each generation designated transmission customer in the area-of-benefit on the basis of each customer's average injection; and

(c) to the extent practicable, limit the need for Transpower to exercise discretion; and

(d) result in charges that are consistent with the identification of benefits (if any) in relation to the relevant investment proposal; and

(e) be consistent in its application as between major capex and base capex; and

(f) for each high value investment commissioned on or after the date of these guidelines, provide for Transpower to adjust a customer's charges to reflect—

(i) any marginal saving to Transpower from the customer's credible commitment to reduce its demand for transmission services, if that commitment results in Transpower changing its investment plans resulting in a reduction in costs; or

(ii) any marginal increase in costs to Transpower from the customer's credible commitment to increase its demand for transmission services, if that commitment results in Transpower changing its investment plan resulting in an increase in cost; and

(g) provide for Transpower to consult with interested parties about the areas that are likely to benefit from the investment, and the extent of any such benefit.

11. The simplified method must—

(a) to the extent practicable, be simple to apply and administer; and

(b) to the extent practicable, be simple for a party paying the charge to ascertain why the party is subject to the area-of-benefit charge; and

(c) for each eligible investment, identify each designated transmission customer that is expected to receive a positive net benefit from the eligible investment, unless doing so would unduly prejudice the requirements of paragraphs (a) and (b), in which case the method must identify the designated transmission customers expected to receive the majority of the positive net benefits; and

(d) to the extent practicable, provide for the allocation of charges to the beneficiaries identified in paragraph (c), so that each beneficiary is allocated the proportion of the charges that corresponds to the share that the beneficiary is expected to receive of the aggregate positive net benefits expected to be received by all identified beneficiaries; and

(e) to the extent that the method in paragraph (c) is not practicable, provide for—

  (i) charges to be allocated to each identified beneficiary that is a load designated transmission customer on a physical capacity basis; and

  (ii) charges to be allocated to each identified beneficiary that is a generation designated transmission customer on the basis of each customer's average injection; and

(f) be phased in over a short a period of time as is practicable after the standard method takes effect.

12. The method for determining physical capacity for the purposes of clauses 10(b)(i) and 11(e)(i) must be the same as the method used to determine physical capacity for the purposes of clauses 24 to 29.

13. For the purposes of clauses 9(a) to (c), 10(a), and 11(c) to (d), the TPM must provide for expected benefits to be assessed as follows:

  (a) for eligible investments commissioned before 1 April 2019, as at 1 April 2019, for the expected remaining life of the investment:

  (b) for all other eligible investments, as at the date of commissioning or the completion date (as the case may be), for the expected remaining life of the investment.

14. Except as provided for in clauses 15 and 16, the TPM must, for the purposes of determining the area-of-benefit charge, provide for—

  (a) assets in eligible investments commissioned before the date of these guidelines to be valued on a depreciated historical cost (**DHC**) basis; and

  (b) assets in eligible investments commissioned on or after the date of these guidelines to be based on a replacement cost (**RC**) basis.

15. In relation to any asset to be valued at replacement cost, the TPM must provide that—

    (a) Transpower must determine the expected life of the asset at the time of commissioning; and

    (b) subject to paragraph (c) and clause 16, the area-of-benefit charge must be set so as to recover the cost of the asset and the capital cost of holding the asset over its full expected life; and

    (c) in case of a force majeure event, the value of the asset must be depreciated to its residual value and its expected life adjusted accordingly.

16. The TPM must provide that, if Transpower undertakes replacement, refurbishment or maintenance expenditure that extends the expected life of an asset, the replacement, refurbishment or maintenance expenditure would be capitalised and charged for as a new asset with a life equal to the new expected life of the asset.

17. The TPM must provide that designated transmission customers may apply to Transpower—

    (a) to have the value of an asset in an eligible investment commissioned before the date of these guidelines optimised from DHC to optimised depreciated historical cost (**ODHC**).

    (b) to have the value of an asset in a high value investment commissioned on or after the date of these guidelines optimised from RC to optimised replacement cost (**ORC**).

18. The TPM must provide that, if Transpower receives an application to have an asset optimised as described in clause 17, Transpower must optimise the value of the asset in the following circumstances:

    (a) for an asset in an eligible investment commissioned before the date of these guidelines, if the ODHC for the asset is less than 80% of the DHC for the asset:

    (b) for an asset in a high value investment commissioned on or after the date of these guidelines and before the investment has been commissioned for the period of time specified in the TPM, if—

        (i) a single customer disconnects from the grid causing the ORC for the asset to reduce by more than 20%; and

        (ii) the ORC for the asset is less than 80% of the RC for the asset:

(c) for an asset in a high value investment commissioned on or after the date of these guidelines and after the investment has been commissioned for the period of time specified in the TPM, if the ORC for the asset is less than 80% of the RC for the asset.

19. The TPM must—

(a) include a method and process for Transpower to determine the ODHC or the ORC for an asset; and

(b) specify a period of time for the purposes of clauses 18(b) and (c), which must be sufficient to ensure that the prospect of optimisation has a negligible impact on customers' motivation to seek new investment; and

(c) provide for Transpower to have the discretion to revise the ORC or ODHC for an asset, if demand for the asset changes by more than 20%.

20. Transpower would have the discretion to remove optimisation altogether if, following a revision under clause 19(c), the criteria for optimisation is no longer met.

21. The TPM must include a method and process for—

(a) Transpower to review the application of the area-of-benefit charge for a high value investment if there has been a material change in circumstances, and adjust the charge if necessary; and

(b) Transpower to decide when a material change in circumstances has occurred, which must include consultation with interested parties about whether there has been a material change in circumstances before proceeding to review any area-of-benefit charge.

22. The TPM must provide for the area-of-benefit charge to include an allocation for maintenance and operating expenses that is at least broadly cost-reflective.

Residual charge

23. The TPM must provide for the recovery of any revenue not otherwise recovered by the TPM (or any lesser amount determined by Transpower) through a capacity-based charge on load designated transmission customers (called the residual charge), allocated according to the proportion that the physical capacity of each load designated transmission customer's connection to the grid bears to the total physical capacity of all load designated transmission customers' connections to the grid.

24. For the purposes of clause 23, the TPM must specify whether physical capacity is—

(a) each customer's transformer capacity in the 12 months prior to 17 May 2016; or

(b) each customer's line capacity in the 12 months prior to 17 May 2016; or

(c) each customer's gross anytime maximum demand in the 5 years prior to 17 May 2016.

25. If clause 24(c) applies, the TPM must specify whether gross anytime maximum demand for a customer is—

(a) the customer's highest gross demand in the 5 year period; or

(b) the average of the customer's highest gross demand in each of the 5 years; or

(c) the average of the customer's 5 highest gross demands in the 5 year period; or

(d) another measure of gross anytime maximum demand.

26. To the extent practicable, and to the extent that the transaction costs of doing so would not be prohibitive, gross anytime maximum demand calculated under clause 24(c) must be anytime maximum demand, including—

(a) the quantity of electricity generated by generation connected to the customer's network; and

(b) the volume of demand-side management and demand response on the customer's network.

27. Clause 28 applies if—

(a) a period of time (in years) specified in the TPM for the purposes of this clause and clause 28 has elapsed since the guidelines were published; and

(b) there has been a material change in circumstances.

28. Transpower may substitute the time period in relation to which physical capacity is calculated under clause 24 with another time period—

(a) of the same duration; and

(b) that ends on the date that is the period of time (in years) specified in the TPM before the date of substitution.

29. The TPM must specify a period of time (in years) for the purpose of clauses 27(a) and 28(b).

Overhead and unallocated operating expenses (overheads)

30. The TPM must provide for Transpower's overhead and unallocated operating expenses to be recovered—

(a) from generation designated transmission customers, through the connection charge; and

(b) from load designated transmission customers, through the residual charge.

31. The overheads must be allocated on substantially the same basis, and with the same effect, as the TPM in force on the date of these guidelines.

Allocation of charges to new designated transmission customers

32. The TPM must allocate charges to a person that becomes a designated transmission customer after the new TPM comes into force on the same basis as if the customer was an existing customer on the date the new TPM takes effect.

33. The area-of-benefit and residual charges for a new designated transmission customer must be based on a proxy for, but must not be dependent on, the physical capacity after the participant becomes a designated transmission customer.

Prudent discount policy

34. The TPM must include a prudent discount policy on the same basis (and with the same effect) as the prudent discount policy in the TPM in force on the date of these guidelines, except as provided for in clauses 35 to 41.

35. The TPM must provide that, subject to clause 39(b), a prudent discount would apply for the expected life of the asset to which the prudent discount relates, unless a shorter prudent discount is agreed between Transpower and the party receiving the prudent discount.

36. The TPM must provide that a prudent discount would be available if it is privately beneficial for a load designated transmission customer to build generation to disconnect from the grid, but not efficient and not for the long-term benefit of consumers.

37. The TPM must provide that a prudent discount would be available to a direct consumer if—

    (a) the direct consumer's transmission charges are an amount that represents a material portion of the consumer's input costs and/or business profits; and

    (b) there is a material risk that transmission charges would cause the direct consumer to close down its New Zealand plant (and so disconnect from the grid); and

    (c) the customer's business profits have been heavily affected by market conditions; and

    (d) the direct consumer has taken reasonable steps to remain viable as a going concern, including taking significant steps to eliminate unnecessary costs.

38. The TPM must provide that a prudent discount would be available to a distributor if the distributor can demonstrate that there is a material risk that—

    (a) transmission charges would cause one of the distributor's customers to disconnect from the distributor's network; and

(b) if the distributor's customer was a direct consumer in the same circumstance as described in clause 37, the distributor's customer would be eligible to receive a prudent discount.

39. A prudent discount under clause 37 or 38 must—

(a) be linked to key factors that would have a material effect on the decision to disconnect from the grid (for example, the world price of the product or service produced by the customer); and

(b) be able to be reduced or suspended if the key factors relied on in granting the prudent discount change such that the prudent discount would not have been granted, or would not have been granted on the same basis.

40. The TPM must—

(a) provide that a prudent discount will be available if a load designated transmission customer's transmission charges exceed the standalone cost of delivering electricity to the load designated transmission customer; and

(b) provide that a prudent discount will be available to a distributor in respect of a load customer of the distributor if Transpower is satisfied that, if the load customer was a direct consumer, the prudent discount would be available on the basis specified in paragraph (a); and

(c) include a method for determining whether standalone cost is exceeded for the purposes of this clause.

41. The TPM must provide that any prudent discount must not result in a customer paying less than the incremental cost of supplying it with transmission services.

42. The TPM must include methods and processes for assessing applications and calculating prudent discounts in the circumstances described in clauses 35 to 41.

Additional components

43. The TPM must include any or all of the following additional components if their inclusion is practicable and consistent with the requirements of clause 12.89 of the Code:

(a) a requirement that, if an asset that will ultimately not be classified as a connection asset is commissioned such that it meets the definition of connection asset, it must be charged for as a connection asset while it meets that definition:

(b) a method to ensure that the charges that apply to assets that provide connection services are not affected by a person (other than Transpower) connecting assets to assets owned by Transpower:

(c) a method for allocating operating and maintenance costs in relation to which the area-of-benefit charge or connection charge applies to parties that pay charges in relation to that asset, on an actual-cost basis:

(d) a long-run marginal cost (LRMC) charge that—

  (i) is designed to promote the efficient use of Transpower's grid assets that are not connection assets, so as to efficiently defer investment; and

  (ii) complements or augments, but does not duplicate, the price signals provided by nodal pricing and other charges under the TPM:

(e) a kVar charge on reactive load.

44. If an LRMC charge is included in the TPM, the TPM must specify that the purpose of the LRMC charge is to promote a change in the use of the interconnected grid in order to efficiently defer investment, after taking account of nodal prices and other transmission charges.

45. Transpower may only include an LRMC charge in the TPM if a price signal over and above the price signal provided by nodal pricing (or that could be provided by nodal pricing with direct refinements to the spot electricity market) and other transmission charges is necessary to promote efficient investment in, and use of, the interconnected grid.

46. If a kVar charge is included in the TPM, the TPM must specify the circumstances in which the kVar charge would apply and in which regions.

47. If Transpower does not include any of the additional components in the TPM initially developed under these guidelines, it would be desirable for Transpower to keep each of the components not included under review and consider, whether to propose a variation under clause 12.85 of the Code to include any one or more of them.

Appendix B Modelling of charges under the proposals

The scenario

Overview

B.1 The area-of benefit TPM option described in this paper, and the status quo TPM, are applied to a hypothetical future scenario. The scenario covers a 1-year period, which is intended to represent the 2019 calendar year (compared with the TPM options working paper, where the scenario loosely represented a period from 2017 to 2019).

B.2 The scenario assumes demand growth of approximately 1% per year between 2014 and 2019.[260]

B.3 The scenario assumes that:

B.4 two coal-fired Huntly Rankine units are available

(a) Otahuhu B is not available

(b) Southdown is not available (apart from the 35 MW peaking plant).

This is a key change from the modelling in the TPM options working paper, in which it was assumed that all the above generating units would be available.

B.5 The scenario assumes that a new 50 MW geothermal plant will be commissioned near Wairakei at the start of 2019 (in order to meet demand growth). No other new generation investment is modelled.

Implementing the scenario in vSPD

<u>Approach</u>

B.6 The scenario has been implemented using the Authority's vSPD model.261 Minor modifications have been made to the vSPD code for this purpose, aimed mainly at producing the required outputs.[262]

B.7 The only significant change to the operation of vSPD is to deal with ramp rates. In the standard version of vSPD the output from each generator at the start of each period is an exogenous input. In the TPM version of vSPD, the generation from the previous period is used to set the generation at the start of the next period.

B.8 The scenario is produced by:

(a) taking real final pricing cases from the 2014 calendar year, in the GDX format used by vSPD

(b) modifying the GDX files as described below

(c) using the (slightly modified) version of vSPD to solve the cases

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[260] The Authority is aware that actual demand growth may be faster or slower than this, but notes that previous analysis has shown that area-of-benefit and deeper connection charges are not particularly sensitive to overall demand growth rate assumptions.

[261] http://www.emi.ea.govt.nz/Tools/vSPD.

[262] The TPM vPSD model is based on version 1.3 of vSPD.

(d) loading selected vSPD output files into a SQL database. (The Authority will publish a copy of this table, so that participants can reproduce the calculation of simulated charges without needing to rerun vSPD).

B.9 The 2019 year of the scenario is based on modified 2014 final pricing cases.

B.10 This is a change from the modelling in the TPM options working paper, which instead used final pricing cases from 2011 to 2013.

Demand assumptions

B.11 Demand at all nodes except Tiwai and Kawerau is scaled up by 5% in 2019 (compared to 2014).

B.12 Demand at Tiwai and Kawerau is unmodified.

B.13 The Authority has not modelled TPM charges under a Tiwai closure scenario. Such a scenario would differ so greatly from recent history, that it would be difficult to model using the tools used to date.

B.14 Demand-side bids are modelled at the following nodes: KAW0112, KAW0113, KIN0111, KIN0112, KIN0113, WHI0111. These bids are based on actual bids into the spot market price-responsive schedule (PRS).

B.15 The Authority appreciates that, in practice, some of these parties might not place dispatchable demand bids. However, modelling these demand-side bids in the scenario helps to represent the price sensitivity of the relevant loads.

B.16 In modelling transmission charges, no attempt is made to consider how the various transmission charging options might affect demand-side behaviour.

Generation assumptions[263]

B.17 Otahuhu B, and the main generating plant at Southdown, are assumed to be unavailable.

B.18 Synthetic offers are used for:

(a) the two remaining coal-fired Rankine units at Huntly – with roughly half the capacity being offered at $5/MWh, and the remainder offered at up to $100/MWh

(b) Contact's Stratford CCGT – with roughly half the capacity being offered at $0/MWh, and the remainder offered at prices ranging between $40/MWh and $55/MWh

(c) an additional 20 MW tranche of generation capacity at Whakamaru[264] – offered at $300/MWh, or $50/MWh above the highest priced existing tranche, whichever is higher

(d) the new 50 MW geothermal generator – modelled as baseload

(e) Te Mihi and Ngatamariki geothermal – modelled as baseload

[263] The Authority's assumptions about the amount of generation injected into the national grid by Pioneer at CYD0331 is an estimate only.

[264] Refer to: NZ Energy and Environment publication, 12 November 2014, Vol 11, No. 30, page 1.

(f) Mill Creek wind – output assumed to be proportional to West Wind, and located at West Wind.

B.19 No attempt is made to track simulated hydro storage or to consider how this might result in changes to generation offers (relative to the actual offers made in 2014).

B.20 In modelling transmission charges, no attempt is made to consider how the various transmission charging options might affect generator behaviour.

B.21 Aniwhenua hydro generation is now assumed to belong to Southern Generation.[265]

Transmission network assumptions

The scenario has been updated to use the network configuration from 20th January 2016.

B.22 The network configuration has been modified to include the LSI reliability upgrade and the Arapuni bus split has been closed.

B.23 Shoulder and summer line ratings are modelled as being 95% and 90% of the winter line rating, respectively.

B.24 Where a node does not exist in the 20 January 2016 network configuration, its demand is shifted to a node that does exist:

(a) load at the KEN bus is moved to MPE1101

(b) load at ADD, BRY, SPN and MLN is moved to ISL0661

(c) load at GIS, TUI and WRA is moved to TUI1101

(d) load at MOT and MPI is moved to STK0331

(e) load at PAL is moved to HWB0331.

B.25 Instantaneous reserve requirements are adjusted to reflect the availability of the bipole HVDC throughout the three-year period. In particular:

(a) DCCE i_HVDCPoleRampUp is set to 528

(b) i_TradePeriodBranchCapacity is set to approximately 700 for the HVDC poles

(c) additional types of risk parameter associated with Pole 3 commissioning are removed.

B.26 Group and branch constraints are turned off in the vSPD modelling:

(a) in order to avoid the difficulty of determining the constraint parameters that will apply in 2019

(b) to reflect that most constraints that might bind would either be managed operationally or resolved through investment

(c) on the assumption that the results of interest (simulated transmission charges) are not sensitive to the inclusion of group and branch constraints – which is supported by analysis to date.

265 See eg http://www.stuff.co.nz/business/74612659/southern-generation-buys-north-island-power-station-for-100m .

B.27 Some potential future investments are not included in the scenario. Among these are:

(a) investment in the North Taranaki network[266] – because there is uncertainty about the investment option that will be adopted, and the distribution of charges between parties may depend on the choice of investment option

(b) investment in the lower Waitaki Valley, as listed in the Transpower ITP[267] – on the basis that this could potentially be a connection investment

(c) CPK-WIL B reconductoring, as listed in the Transpower ITP – on the basis that the Authority understands that this would be a connection investment

(d) some projects from the Transpower ITP that are generic rather than specific (eg 'LNI transmission reinforcement', 'Unidentified reconductoring projects')

(e) some projects from the Transpower ITP that are not expected to be completed by 2020 (eg OTB-HAY reconductoring)

(f) a 'Wellington supply security' investment listed in Transpower's RCP2 proposal – on the basis that it is relatively small in size, as yet not clearly defined, and might include connection investment

(g) various work programmes such as 'transformer replacements' and 'tower painting' that are made up of individually small expenditures (even though they may add up to substantial amounts of money in aggregate).

Revenue to be recovered

B.28 It is assumed Transpower's revenue requirement (including connection) will be $917million per year. This is the same figure as was used in the TPM options paper, and is broadly consistent with Transpower's forecast revenue.[268]

B.29 The revenue requirement is expressed, and all charges are calculated, on a '$M per calendar year' basis – c.f. the '$M per pricing year' basis actually used by Transpower.

B.30 It is assumed that $55M per year of post-FTR non-connection LCE will be available as a credit against transmission charges – with post-FTR LCE arising on the HVDC link making up $5M of this.

Simplifying assumptions applied in the calculation of transmission charges

B.31 This section of the Appendix is not exhaustive but covers the main simplifying assumptions.

B.32 The subsections relating to specific charges are not intended to be stand-alone – they should be read alongside the descriptions of the corresponding charges in the main text.

266 https://www.transpower.co.nz/projects/north-taranaki-interconnection-investigation#zoom=7&lat=-39.0583&lon=174.028&layers=BT.

267 https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

268 Refer: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/RCP2%20revenue%20-%20revised%20forecast%20%28July%202014%29.pdf.

B.33 This section does not discuss the connection charge, the LRMC charge, or the kVar charge, which are not modelled in this paper.

Aggregation of parties

B.34 Transmission charges are calculated and shown for the following major industrial consumers – even though in fact they are embedded in a distributor's network and are not Transpower customers:

(a) Carter Holt Harvey at Kinleith

(b) Daiken MDF

(c) New Zealand Refining.

B.35 The reason for 'breaking out' these major industrial consumers is to provide transparency about the modelled charges applying to their load (and generation, where applicable). The Authority appreciates that in practice, these charges could be levied on the distributor and passed on to the consumer, rather than being levied on the consumer directly.

B.36 At the request of the parties involved, transmission charges are calculated and shown for the following geothermal generators:

(a) Mokai JV

(b) Nga Awa Purua JV

(c) Ngatamariki

(d) Tuaropaki.

B.37 The Authority has not modelled transmission charges, whether direct or passed through, on:

(a) other embedded loads

(b) small to medium distributed generators.

B.38 In the TPM options working paper:

(a) transmission charges were not shown for some Transpower customers that consume a relatively small amount of electricity directly from the grid, ie Solid Energy and Southpark

(b) the networks making up Powernet were combined for modelling purposes

(c) Unison and Centralines were combined for modelling purposes.

B.39 Most of these issues have now been addressed – ie The Power Company, OtagoNet JV, Electricity Invercargill, Lakeland Network, Unison and Centralines are all shown separately.

B.40 However, due to data limitations, Network Tasman and Nelson Electricity are still combined for modelling purposes.

B.41 Charges for Fonterra have been calculated but are not shown, because they only cover a minority of Fonterra's sites (ie those that are connected directly to the grid) and would not provide a good representation of the transmission charges paid (directly and indirectly) by Fonterra.

B.42 Charges for Pacific Steel are not shown, due to the planned closure of the Auckland mill.[269]

Area-of-benefit charge

B.43 Transpower has provided an interim indicative revenue requirement for each investment modelled by vSPD (see the Table below). Together, these investments represent the area-of-benefit revenue requirement, totalling about $295 million per year.

B.44 In practice, Transpower would calculate the revenue requirement for each investment based on calculated capital and O&M cost figures.

B.45 The identification in this paper of the beneficiaries of each investment, and the percentage of costs recoverable from each group of beneficiaries, is also an approximation for modelling purposes only. If this option was adopted, Transpower would identify beneficiaries and allocate costs between them.

B.46 The physical capacity of each load party at each node is assumed to be 100% of the AMD of that party at that node. In practice, the ratio of physical capacity to AMD would vary.

<u>Investments that would be subject to the area-of-benefit charge</u>

B.47 The investments that are modelled as being subject to the area-of-benefit charge are set out in Table 7.

B.48 Only the first six investments in the table below (NIGU through to Wairakei Ring) are modelled in vSPD. The remainder have used a regional allocation, as noted in the table below, to approximate the distribution of benefits expected to arise.

Table 7 : Investments modelled as being subject to the area-of-benefit charge

Investment	Reference	Modelled amount to be recovered ($M per year)	Modelled group of beneficiaries	Modelled % recovery from this group
NIGU	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/north-island-grid-investment-proposal/	85	Full recovery by by vSPD method	n/a
Pole 3	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/hvdc-grid-upgrade/	73	Full recovery by by vSPD method	n/a

[269] See eg http://www.nzherald.co.nz/business/news/article.cfm?c_id=3&objectid=11204042. Ideally modelled demand at the site would have been set to nil, but this was not done. Instead, the charges have been calculated but are not shown.

Investment	Reference	Modelled amount to be recovered ($M per year)	Modelled group of beneficiaries	Modelled % recovery from this group
Pole 2	N/A	45	Full recovery by by vSPD method	n/a
NAaN	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/	39	Partial recovery by vSPD method (49%)	n/a
			Loads at and north of Hepburn Rd	51%
LSI Renewables	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-renewables/	4.16	Full recovery by by vSPD method	n/a
Wairakei Ring	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2008-gup/wairakei-ring-economic-investment-history/	15	Full recovery by by vSPD method	n/a
Otahuhu GIS	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/otahuhu-substation-diversity-proposal-history/	12	Loads at and north of Bombay	100%
BPE-HAY reconductoring	http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/bunnythorpe-haywards-a-and-b-lines-conductor-replacement-investment-proposal/	6	All North Island generators	50%
			All South Island generators	50%
USI reactive support (IGE 4)	https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/grid-development-proposals-archive/ige-applications/upper-south-island-reactive-support-history/	3	South Island loads in and north of Christchurch	100%
UNI dynamic reactive support	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/upper-north-island-dynamic-reactive-support-investment-proposal-archive/	6	Loads at and north of Bombay	100%

Investment	Reference	Modelled amount to be recovered ($M per year)	Modelled group of beneficiaries	Modelled % recovery from this group
LSI Reliability	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/	2	Load at Tiwai, at Invercargill and in the Southland 110 kV network	100%

Capacity-based residual charge

B.49 The capacity based residual charge recovers the revenue not otherwise recovered by connection or the area-of-benefit charges (approximately $500m/year). It is levied on load customers only.

B.50 The residual charge is allocated amongst load customers by physical capacity.

B.51 The physical capacity of each load party at each node is assumed to be 100% of the AMD of that party at that node. In practice, the ratio of physical capacity to AMD would vary.

B.52 The modelling does not take into account any attempts of parties to reduce their deemed physical capacity.

B.53 Carter Holt Harvey has advised that ‘we also have a substation rebuild coming in the next few years and the transformer size is likely to expand by 10 MVA for T1, T2 and T3’.[270] This potential change is not included in the modelling in this paper.

HVDC charges – status quo

B.54 HVDC charges are allocated to South Island direct generators and distributors. Following Transpower’s operational review, charges are allocated to South Island injection locations in proportion to their MWh injection into the national grid.

B.55 In the modelling, charges are calculated based on injection over the three years of the scenario. This is a reasonable approximation to the actual HVDC charge, which is calculated over a longer period.

B.56 HVDC charges have been calculated with regard to calendar years rather than pricing years or measurement years.

Interconnection charges – status quo

B.57 Interconnection charges are allocated to load customers, in proportion to their mean offtake in regional peak periods. Following Transpower’s operational review:

(a) N=100 regional peak periods per year are used in all four regions of the country (UNI, LNI, USI and LSI)

(b) periods falling between October and March inclusive are not eligible to be considered regional peaks in the UNI, LNI and LSI regions.

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270 http://www.ea.govt.nz/dmsdocument/19656.

B.58 The calculation of interconnection charges in this work is approximate and includes some simplifying assumptions (eg, with respect to the calculation of interconnection charges on offtake at grid-connected generation nodes). Parties should not rely on it to form conclusions about the interconnection charges they will pay. They should contact Transpower if they have any questions about the interconnection charge.

B.59 Interconnection charges have been calculated with regard to calendar years rather than pricing years or measurement years.

Deeper connection charge

B.60 The revenue requirement associated with each asset (including capital cost recovery and O&M) is assumed to be 15% of DHC. This is an approximation. In practice, the ratio of revenue requirement to DHC would vary between assets.

B.61 The representation of the transmission grid used in applying the flow tracing approach differs from the actual grid in some respects, and is intended for calculating indicative charges only.

B.62 The tables mapping between Transpower assets and vSPD assets may include some inaccuracies, and again are intended for calculating indicative charges only.

B.63 In the TPM options working paper, some connection assets were mistakenly identified as interconnection (and hence were eligible for the deeper connection charge) and some interconnection assets as connection. The Authority has corrected some of these errors and revised some assumed asset costs.

B.64 Deeper connection charges are calculated for wind generation nodes—cf, the analysis carried out for the TPM options working paper, where these nodes were not included in the calculation of deeper connection charges.

B.65 Some planned or proposed investments are not included in the main deeper connection calculation—in large part, because it is not clear what form these investments will take, or what the asset-level costs will be. Instead, the allocation of charges for these investments is carried out on an ad hoc basis, based on the Authority's understanding of the parties that would likely be deemed to be 'connected by' the relevant assets. These investments are:

(a) remaining elements of LSI Renewables—$13 million to be recovered per year, assumed to be from lower South Island generators

(b) LSI Reliability—$3 million per year, mainly from The Power Company with small shares from Rayonier and Meridian

(c) PAK-WKM series compensation—$7.5 million per year, mainly from Vector with a small share from Northpower

(d) OTA-WIR reinforcement—$3 million per year, from Counties Power[271]

(e) OTA and PEN ICTs—$3 million per year, from Vector

[271] In practice, other parties such as Vector might pay some or all of the costs, depending on the nature of the investment.

(f) BPE-WIL reconductoring—$7.5 million per year, mainly from Wellington Electricity with small shares from Powerco and Electra.

B.66 *For the deeper connection option where charges to load are allocated according to physical capacity:* The physical capacity of each load party at each node is assumed to be 160% of the AMD of that party at that node. In practice, the ratio of physical capacity to AMD would vary.

B.67 In the modelling, post-FTR LCE associated with a deeper connection asset is used to offset the charges for that asset. The calculation of post-FTR LCE is approximate (eg, in that the vSPD modelling used in the scenario does not include group constraints, and the effect of the FTR market on the amount of LCE available to offset transmission charges is not modelled in detail).

Worked example of the deeper connection method

<u>Calculation of modelled deeper connection charges levied on Powerco and Contact for BPE_BRK1.1, BPE_BRK2.1</u>

B.68 BPE_BRK1.1 and BPE_BRK2.1 are 220kV circuits connecting the Bunnythorpe and Brunswick substations. In the scenario, they are primarily used for export from Taranaki, but are also used for import into Taranaki at times.

B.69 In the modelled scenario:

(a) the load HHI of these circuits is 2,462 – based on mean flow shares of:

(i) 55.8 MW to Wellington

(ii) 37.9 MW to the central North Island

(iii) 13.8 MW to Canterbury (through the HVDC link)

(iv) 8.6 MW to Otago/Southland (ditto)

(v) 7.8 MW to Auckland

(vi) 6.1 MW to Taranaki

(vii) 11.8 MW to all other regions combined

resulting in a load cutoff factor of (2,462 – 2,000) / 5,000 = 9.2%

(b) the generation HHI of these circuits is 8,766 – based on mean flow shares of:

(i) 138.0 MW from Taranaki

(ii) 6.4 MW from South Canterbury (through the HVDC link)

(iii) 1.9 MW from the central North Island

(iv) 1.3 MW from Waikato

(v) 0.3 MW from all other regions combined

resulting in a generation cutoff factor of 100%.

B.70 The depreciated historical cost of these circuits is assumed to be $6.9 million. The annual recoverable amount is assumed to be 15% of this, or $1.03 million.

B.71 ‘Deeply connected’ load nodes include:

(a) BPE0331, with a mean flow share of 18.4 MW through these circuits

(b) CPK0331, 10.4 MW

(c) TKR0331, 7.0 MW

(d) WIL0331, 7.0 MW

(e) GFD0331, 5.4 MW

(f) TWI2201, 5.2 MW

(g) LTN0331, 4.8 MW

(h) PRM0331, 4.7 MW

(i) MLG0331, 3.9 MW

(j) various others, totalling 75.7 MW

with the sum being 142.4 MW.

B.72 'Deeply connected' generation nodes include:

(a) SFD2201 SPL0, with a mean flow share of 117.9 MW through these circuits

(b) SFD2201 SFD21, 9.7 MW

(c) SFD2201 SFD22, 9.9 MW

(d) BEN2202 BEN0, 3.8 MW

(e) all others combined, 6.3 MW

with the total being 147.6 MW.

B.73 On this basis, two examples of calculations of deeper connection charges at specific nodes are:

(a) BPE0331 pays (18.4 x 9.2%) / (142.4 x 9.2% + 147.6 x 100%) = 1.05% of the total recoverable amount, which is $1.03 million per year, so $11 thousand per year

(b) SFD2201 SPL0 pays (117.9 x 100%) / (142.4 x 9.2% + 147.6 x 100%) = 73.5% of the total recoverable amount, which is $1.03 million per year, so $755 thousand per year.

B.74 The above calculation is applied across nodes, and summed to the participant level. For instance:

(a) Powerco is modelled as paying $11 thousand per year (BPE0331) + $2.9 thousand (LTN0331) + $2.0 thousand (MST0331) + $1.3 thousand (BRK0331) … = $22 thousand per year

(b) Contact is modelled as paying $755 thousand per year (Stratford CCGT) + $127 thousand (Stratford peakers) … = $885 thousand per year.

B.75 These charges would be partly offset by LCE arising on the assets.

Appendix C Cost-benefit analysis of the TPM proposal

Cost Benefit Analysis of Transmission Pricing Options

prepared for:
NZ Electricity Authority

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DISCLAIMER

This report has been prepared for the New Zealand Electricity Authority ("Authority") for the purposes of assessing the costs and benefit of different transmission pricing options.

The analysis and information provided in this report is derived in whole or in part from information prepared by a range of parties other than Oakley Greenwood (OGW), and OGW explicitly disclaims liability for any errors or omissions in that information, or any other aspect of the validity of that information. We also disclaim liability for the use of any information in this report by any party for any purpose other than the intended purpose.

DOCUMENT INFORMATION

Project	Cost Benefit Analysis of Transmission Pricing Options
Client	NZ Electricity Authority
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Executive Summary

Background

The Electricity Authority (Authority) is proposing to prepare a second issues paper as the next step of a review of the transmission pricing methodology (TPM). That second issues paper will include proposed new draft TPM guidelines with four main components, including what is termed the Area-of-Benefit (AoB) charge. The document presents a Cost Benefit Analysis (CBA), which was commissioned prior to deciding that the AoB was the preferred option and looks at two options, being:

- Option 1: Deeper connection-based charge; and
- Option 2: AoB charge.

The three other main components are a connection charge, a residual charge, and a prudent discount policy.

The new draft TPM Guidelines will also include five "additional components" that could each form part of a proposed TPM.

Transpower, in developing the TPM, could include any or all of the additional five components in the TPM if that would be practicable and consistent with the requirements of clause 12.89 of the Electricity Industry Participation Code 2010 (Code). These include:

- Clarification of charging for staged commissioning of connection assets;
- A method for charging for transmission assets that were originally classified as connection assets but subsequently become non-connection assets due to other investment;
- Within the AoB and connection charges, actual cost-based operating and maintenance costs;
- Long run marginal cost charge; and
- kVar charge.

The second issues paper also outlines two further changes to the Code relating to loss and constraint excess and to power factor requirements.

Objective

The Authority has engaged Oakley Greenwood (OGW) to undertake a quantitative cost benefit analysis (CBA) to support the assessment of the TPM options that will be included in its second issues paper, against the counterfactual case.

This report reflects the results of our assessment.

CBA framework

OGW has developed a cost-benefit analysis model (CBA Model) that compares the net present value (NPV) of the economic costs and benefits of the different options relative to the base case (status quo).

The CBA Model uses an incremental approach to comparing the options with the base case. This means that costs and/or benefits that would have arisen through the base case scenario have been “netted-off” from the costs and benefits of the two options.

An NPV analysis of the incremental costs and benefits is then undertaken to provide an accurate comparison of the options and to remove any timing differences between the costs and benefits.

Sensitivity testing regarding discount rates, term of analysis and forecasts provide a more complete picture of the different options and what is driving the outcome of the calculations.

To be clear, in accordance the Authority’s interpretation of its statutory objective, our CBA model focuses exclusively on assessing the changes in economic efficiency stemming from the proposed transmission pricing options. Distributional impacts (i.e., wealth transfers) that might stem from a change in transmission pricing arrangements (except to the extent that they affect efficiency) are excluded.

Economic Objective of sending more cost-reflective transmission price signals

A key component of any CBA is to define the problem (or objective) that the proposed solution is trying to solve (or achieve). At a high level, the Authority has expressed the overarching *economic* objective of any transmission pricing arrangement as maximising:

> *the overall efficiency of the electricity industry for the long-term benefit of electricity consumers. Overall efficiency refers to both efficient use of the grid and efficient investment in the electricity industry - the grid, generation and demand-side management.*

A CBA should therefore give explicit consideration to how a price signal for transmission services will lead to efficient investment and operation across the supply chain. In particular, it is important to clearly identify:

- Which transmission services will be subject to the new pricing arrangements; and
- Which transmission services would, if priced, facilitate the achievement of the overarching economic objective.

Having regard to the above, we have conceptualised that there would be an economic benefit in reflecting the following proto-typical costs incurred by a transmission business in prices which transmission users can be expected to consider in their future use of the network:

- **Forecast augmentation capital expenditure:** As future changes in customer demand can affect the timing and size (and therefore cost) of future augmentation capital expenditure, customers may be able to alter their investment decisions in response to the pricing of this cost driver; and
- **Incremental forecast operating and maintenance expenditure related to change in demand or energy consumption:** As future changes in customer demand and consumption are likely to drive a small amount of future operating expenditure (eg, maintenance costs associated with capacity driven capex).

This means that our starting point is to exclude the following costs from our analysis:

- **Forecast corporate, safety related and IT capital expenditure costs:** We assume these are not discretionary as the timing and scale of these costs will not be affected by changes in future customer demand or energy consumption;

- **Historical investments:** Subject to these costs being recovered in a way that minimises the extent to which they (a) distort future use of the existing network (eg, consumption decisions), and (b) lead customers to make inefficient connection, disconnection or other investment decisions, the recovery of these costs will not impact upon economic efficiency; and
- **Fixed operating expenditure:** We assume that this expenditure will not be influenced by future changes in demand or consumption. This includes costs related to areas such as Finance, Regulation etc.

The area of capital expenditure where we believe there is some uncertainty around whether or not there will be a material economic benefit from sending a price signal that is linked to future expenditure is replacement expenditure.

On one hand, our experience is that with one exception, the efficient[1] *timing* of an electricity network's **forecast replacement expenditure** is generally not materially affected by the demands (or behaviours) that are placed on the network by end customers[2]: rather, it is predominately driven by condition and risk factors unrelated to the loads placed on the asset (or behaviours of end customers). This means that the efficient timing is unlikely to be able to be materially influenced by end customer behaviour.

The one exception arises because the sizing and other technical features of the replacement solution *may* be influenced in part by the decisions and behaviours exhibited by downstream parties. For example, the sizing of a replacement transformer is likely to be linked to the demands expected to be placed on that transformer. However, the benefit, in this context, is the incremental change in costs between the "fully" sized transformer, and the "downsized" transformer, which will be significantly impacted by the economies of scale (or the loss thereof, in this case) associated with making that investment. This diminishes the likelihood that an alternate option is likely to be an economically feasible alternative to the replacement of an existing asset. To this end, we have considered this benefit via sensitivity analysis, as opposed to quantitatively in the base case results.

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1 This assumes that Transpower is operating efficiently. This issue is discussed in more detail in the body of the report.

2 In saying this, we have assumed that the timing of Transpower's replacement expenditure will generally be driven by *Transpower's assessment* of the forward-looking operating and maintenance costs of continuing to operate an existing asset, as well as the probability times consequence of that asset failing. Operating and maintenance costs are predominately a function of maintaining the availability of the asset, not energy throughput or peak demand. The probability of an asset failing is almost de-linked from the end-customer behaviour, rather, it is a function of age, condition, location and other factors that affect its useful life. The consequence of failure is a function of the attributes of the customers served by that asset, as well as other features of the design of the network in that area that may allow load to be switched and served by other parts of the transmission network (or distribution network). Overall, none of the factors driving the efficient replacement of an existing, in situ transmission asset, is likely to be able to be materially influenced by end customer behaviour in our opinion. Further, there are unlikely to be any feasible economic alternatives to replacing existing assets. For example, the economics of permanent embedded generation as an alternative to a centralised (generation, transmission) is limited.

Benefits and costs modelled

Given our economic objective, OGW has conceptualised a number of different potential benefits stemming from a change in the way transmission services are priced. These include that the new price signal may lead to more efficient:

- Future investment in services or equipment that may otherwise be substitutes for capacity related transmission services, thus leading to a reduction in the overall cost of providing electricity services to end customers. In brief, OGW modelled this:
  - By comparing the estimated LRMC of providing transmission services to different regions in NZ, to a number of feasible alternative options for balancing supply and demand, such as demand-side response, embedded generation (in the distribution network) and energy storage; and
  - Assessing whether any of those alternate options were an economically feasible alternative to a transmission connection both "in perpetuity", or as a short-term deferral measure.
- Future investment in electricity generation services, after accounting for the impact that the sizing, location and timing of generation investment has on future transmission investments, thus leading to a reduction in the overall cost of providing electricity services. In brief, OGW:
  - Interrogated the "Interactive Electricity Generation Cost Model – 2015" that is published on the Ministry of Business, Innovation & Employment's website to assess how, after adjusting for a number of recent changes affecting the NZ electricity market, the addition of a transmission price signal that varied by region (based on the estimated LRMC of transmission services to generation customers) would change the order in which new supply is developed in NZ in the future; and
  - Assessed the economic costs stemming from any changes in the "order" in which new generation investment occurs (inclusive of the impact on the transmission network).
- Future consumption and investment as a result of changing the way fixed costs are priced. In brief, OGW considers the way in which historical investments in the NZ transmission network are currently priced may inefficiently impact upon future consumption and investment decisions. As a result, OGW has modelled the impact:
  - That the Interconnection Charge[3] has on future investment decisions by distribution businesses and other parties (e.g. distributed generators);
  - That current charges, in combination with the current Prudent Discount Policy (PDP) might have on the probability of some customers inefficiently exiting the grid; and
  - That the High Voltage Direct Current (HVDC) charge (based on South Island generators' mean injection) might have on future generation investment decisions.

3 Also termed the Regional Co-Incident Peak Demand charge, or RCPD charge, in this report.

- Quantities of services being demanded by the market, thus leading to a reduction in assets needed to meet demand and thus a lower overall cost of providing electricity services. OGW:
  - Modelled the impact that transmission prices have on future volumetric retail prices in NZ under both the base case and under the two main transmission pricing options being modelled; and
  - Estimated the impact that this would have on the quantities of services being demanded by the market (based on the change in the retail price multiplied by the estimated elasticity of demand), and in turn, the costs of providing services to end customers.
- Net incremental costs to the industry have also accounted for:
  - The incremental costs to Transpower and other electricity industry participants of administering and implementing the two transmission pricing options modelled; and
  - The extent to which the two pricing options may assist in avoiding pricing-related costs to the industry.

We have also considered the potential for the pricing options to lead to greater scrutiny of investments by stakeholders, in particular, in terms of providing an incentive for them to reveal their willingness to pay for the services provided by Transpower during the regulatory approval process. Quantifying a net improvement from increased scrutiny is problematic and our CBA has considered this matter via sensitivity analysis, but it is nevertheless certainly positive (and potentially material, even if it only comes about as a result of a small number of otherwise high cost but inefficient projects not being undertaken).

A number of elements of the CBA are inherently difficult to quantify, in particular volumetric impacts on demand and assessment of the degree to which generation and transmission and generation will be more efficiently located and timed over 20 years (the analysis time frame). There is therefore uncertainty around the absolute level of benefit, which reinforces the need for sensitivity testing. However, the purpose of a CBA is to test if benefits outweigh costs and in this analysis the costs are relatively small and benefits range from moderate to significant but in all cases exceed costs by a significant margin.

Results

The following tables highlight the results of our quantitative analysis for both transmission pricing options, using a 20-year evaluation period and an 8% discount rate.

Table 1: Summary of results for the AoB charge compared to base case

Type of benefit	Value (NPV)
Future investment in services that may be substitutes for transmission services	
■ Alternatives to transmission investment (section 8.2.2, part 1)	$1,202,796
■ Deferrals to transmission investment (section 8.2.2, part 2)	$3,010,839

More efficient co-investment in generation and transmission services (section 8.3)[4]	$92,748,124
More efficient quantities of services being demanded (section 8.5)	$313,601
Benefit from more efficient pricing of historical investments	
- Removing the HVDC injection charge based on MWh (section 8.4.2, part 3)	$13,731,094
- Replacement of the Regional Co-Incident Peak Demand (RCPD) charge with a charge based on physical capacity (section 8.4.2, part 1)	$89,974,887
- Introducing a more comprehensive PDP (section 8.4.2, part 2)	$10,302,309
Net incremental and avoided costs (section 9.4)	$2,040,441
NET BENEFIT (COST)	**$213,324,092**

Source: OGW

Table 2: Summary of results for the deeper connection charge compared to base case

Type of benefit	Value (NPV)
Future investment in services that may be substitutes for transmission services	
- Alternatives to transmission investment	$601,398
- Deferrals to transmission investment	$0
More efficient co-investment in generation and transmission services[5]	$92,748,124
More efficient quantities of services being demanded	$143,389
Benefit from more efficient pricing of historical investments	
- Removing the HVDC injection charge based on MWh	$13,731,094
- Replacement of the RCPD charge with a charge based on physical capacity	$89,974,887
- Introducing a more comprehensive PDP	$10,302,309
Net incremental and avoided costs	$405,062
NET BENEFIT (COST)	**$207,906,263**

Source: OGW

4 This represents the average of the two cases - with Huntly being retained ($55m), and without Huntly being retained ($130m).

5 As above

Sensitivity analysis shows that, whilst the results vary depending on the parameters that are changed, a TPM that includes the AoB charge exhibits a:

- Higher benefit-cost ratio than the deeper connection-based charge in all cases (with materially higher qualitative benefits, which are discussed below); and
- Positive benefit-cost ratio in all cases tested.

The stronger result for the AoB charge occurs predominantly as a result of our assumption that the AoB charge will have a significantly greater coverage than the deeper-connection charge with regards to future investment and is also likely to avoid more dispute-related costs than the deeper connection-based charge.

The modelling indicates that there is a benefit from sending a cost-reflective transmission price signal to prospective electricity generators, with the benefit coming about as a result of the co-optimisation of transmission and generation by these prospective generators. The magnitude of this benefit is influenced by our calculation of the LRMC for transmission that is related to the siting and size of future generation investment, which in turn is predominately driven by estimates of future transmission investment within different regions within NZ provided by the Authority. It is also driven by whether or not some generating units at Huntly (Rankine units) are assumed be retained or not (as this drives the level of spare capacity in the generation sector). It is our understanding that there is significant uncertainty around whether the Huntly Rankine units will continue. For the purposes of the analysis we have assumed that there is an equal probability that the Huntly units will be retained or withdrawn and have therefore weighted the incremental benefits of the amended TPMs with and without the Huntly units equally.

A large proportion of the benefits result from the impact on future decisions of more efficient pricing of historical investments, in particular, the move to:

- Levying a smaller residual charge than is currently levied, and
- Basing its recovery on a measure of physical capacity, as opposed to the current RCPD charge.

The latter factor means that future consumption and investment decisions will not materially influence the level of physical capacity (and therefore the charge). This has led us to assume that this benefit would to be the same for both the AoB and deeper connection charge, as the use of physical capacity applies to both. Similarly, transitioning away from charging South Island Generators a HVDC charge based on their mean injections contributes significant economic benefits.

Beyond the quantitative assessment above, there are a number of other qualitative benefits attributable to the AoB charge relative to the deeper connection-based charge, including:

- The structure of the AoB charge – namely the fact that it is a two-part, fixed/variable tariff – means that the customer not only sees a total price that equates to the benefits they receive, but also a cost-reflective marginal price signal. In comparison, the deeper connection-based charge is assumed to simply allocate the full cost of an asset according to use, therefore, it does not send a truly marginal price signal. The lack of a marginal price signal is likely to lead to inefficient outcomes;

- The deeper connection-based charge is based on power flows, therefore it allocates charges according to use rather than benefit. Due to the physics of power flows, the benefit a customer gets from an asset in the grid may be quite different from the use they make of it. This disconnect between the charge a customer pays (based on use) and the benefit they get materially undermines the incentive benefits that can be obtained from service based and cost reflective pricing;
- Transpower would be required to determine the application of the deeper connection-based charge annually, based on a 5-year rolling average of flows. In practice, this creates a new “effective” per MWh charge to recover the cost of assets that have already been constructed. Using a variable price signal to recover the cost of historical investments will in theory lead to inefficient outcomes;
- The deeper connection-based charge is only levied on major users of an investment, therefore its coverage tends to be more localised relative to the AoB charge. This reduces the coverage of the price signal, as well as reducing any potential benefits that might ensue from incentivising greater scrutiny by end customers of Transpower’s proposed investments; and
- The deeper connection-based charge may, in theory, create a locational distortion. Whilst this is unlikely to alter the location decisions of distribution businesses, it may in theory influence their connection decisions, as well as the locational decisions of new generators and direct connect customers.

1. Background

The Electricity Authority (Authority) is proposing to prepare a second issues paper as the next step of the review of the transmission pricing methodology (TPM). That second issues paper will include proposed new draft TPM guidelines with four main components, including what is termed the Area-of-Benefit (AoB) charge. The document presents a Cost Benefit Analysis (CBA), which was commissioned prior to deciding that the AoB was the preferred option and looks at two options, being:

- Option 1: Deeper connection-based charge; and
- Option 2: AoB charge.

The three other main components are a connection charge, a residual charge, and a prudent discount policy.

The new draft TPM Guidelines will also include five "additional components" that could each form part of a proposed TPM.

Transpower, in developing the TPM, could include any or all of the additional six components in the TPM if that would be practicable and consistent with the requirements of clause 12.89 of the Electricity Industry Participation Code 2010 (Code). These include:

- Clarification of charging for staged commissioning of connection assets
- A method for charging for transmission assets that were originally classified as connection assets but subsequently become non-connection assets
- Within the AoB and connection charges, actual cost-based operating and maintenance costs;
- Long run marginal cost charge; and
- kVar charge;

The second issues paper also outlines two further changes to the Code, relating to loss and constraint excess, and to power factor requirements.

2. Objective of this report

The Authority sought a quantitative CBA to support the assessment of the TPM options that will be included in its second issues paper, against the counterfactual case.

OGW was engaged to undertake this task. This report reflects the results of our assessment.

3. Structure of this report

The following sections of this report are structured as follows:

- Section 4 sets out our understanding of the two main options, as compared to the current pricing arrangements;
- Section 5 summarises the framework we have given consideration to when undertaking this CBA;

- Section 6 identifies a number of caveats that need to be considered and understood, prior to reading the remainder of this report;
- Section 7 describes the overarching conceptual framework, and how it is linked to our economic objective, which in turn has underpinned our modelling approach, and a number of the detailed assumptions supporting that modelling;
- Section 8 provides a qualitative description of the key benefits that have been quantified as part of this CBA;
- Section 9 outlines our modelling approach and the key assumptions that have underpinned this CBA;
- Section 10 summarises the results of the modelling, and the sensitivity of those results to changes in key parameters;
- Section 11 provides a qualitative description of a number of other potential benefits and costs stemming from the adoption of the two main transmission pricing options;
- Section 12 outlines our conclusion in relation to the two main transmission pricing options; and
- Section 13 describes our assessment of the secondary options.

4. Our understanding of the two main options, as compared to the current pricing arrangements

4.1. Option 1: Deeper connection-based option

In simple terms, Option 1 would facilitate Transpower imposing a deeper connection charge to the extent possible to **load** and **generation customers** on the basis of flow shares, with costs allocated based on shares of physical capacity for load, or shares of physical capacity or flows for generation. It is our understanding that the assets that are subject to the deeper connection charge must:

- Include transformers, substations, and circuits between nodes; and
- Be related to the results of application of the Herfindahl Hirschman Index (HHI) test of concentration of electricity flows, carried out at the level of clusters of electrically substitutable nodes or transmission regions.

This option would provide for the graduated application of the deeper connection charge to assets with an HHI index of 2000 to 7000. In particular, the deeper connection charge **must not apply** to assets for which the HHI index is less than 2000 and apply fully for assets where the HHI index is more than 7000.

Under the proposed guidelines, Transpower would be required to determine the application of the deeper connection charge annually, based on a 5-year rolling average of flows. This would smooth out variations between periods, and allow for a gradual change in the charge in response to changing use of the grid, limiting the volatility of the charge.

To ensure that Transpower is able to recover its overall revenue requirement, this option would also allow Transpower to impose an additional charge on all customers so that it can recover its residual costs (ie, its total revenue requirement, less the revenue that it expects to recover from imposing the deeper connection-based charge and the LCE and the revenue gathered from the connection charge). It is our understanding that this will be facilitated via the introduction of a capacity charge on load, calculated in proportion to the physical capacity of Transpower's load customers' connection to the grid.

4.2. Option 2: Area-of-benefit-based option

In simple terms, the AoB pricing option would require Transpower to assess who will benefit from an investment in an area, and then charge the beneficiary on the basis of the estimated benefit at the later of:

- The time that the investment is commissioned; or
- The date of the guidelines

Based on information from the Authority, it is our understanding that beneficiaries will be identified (and so charges allocated) on a granular basis – meaning on a nodal basis in most circumstances.

The AoB charge for an eligible investment must then be allocated to load and generation, based on their share of estimated benefits, or where a share of benefits can't be used:

- The physical capacity of load customers; and
- A MWh basis for generation customers[6].

The AoB based charge would:

- Apply to new investments, however the application of the charge to investments below $5m would be phased in to allow the regime to bed in and to reduce the administrative burden on Transpower;
- Apply to a number of high-value existing investments (eg, namely post-2004 investments with a cost greater than $50m and HVDC Pole 2); and
- Reassess the benefits if there is a major change in circumstances to, on a forward-looking basis, review the application of the area-of-benefit charge for each eligible investment to determine whether charges reflected benefits from the investment, and adjust accordingly.

The other key feature of the AoB charge is that it would comprise a fixed and variable component – the latter would be designed to reflect the marginal cost of the asset being priced.

6 However, our assumption is that it will not be charged annually, based on a customer's MWh (ie, this component of a customer's bill will not vary depending on their actual MWh).

Similar to the deeper connection-based charge option, to ensure that Transpower is able to recover its overall revenue requirement, this option would also allow Transpower to impose an additional cost on its customers so that it can recover its residual costs. It is our understanding that this will be facilitated via the introduction of a capacity charge on load, calculated in proportion to the physical capacity of Transpower's load customers' connection to the grid.

4.3. Features common to both – other main components

Both options will be complemented by three other main components, namely:

- A connection charge that charges for connection assets on the same basis, and with the same effect, as the current connection charge;
- A residual charge that is a capacity-based charge on load;
- Prudent Discount Policy (PDP) with substantially the same effect as the current PDP, but with the following enhancements so that the PDP may apply:
    - For the expected life of the asset to which the prudent discount applies;
    - To premature disconnection of load as a result of investment in cases in which it is privately beneficial for a customer to build generation to disconnect from the grid, but not efficient overall; and
    - If there is a material risk that a Transpower customer or a similar EDB customer would exit or where the customer would pay greater than the stand-alone costs of supply.

4.4. A summary of the differences between the two main options and current pricing arrangements

There are three main differences between the two options and the current pricing arrangements. Both options:

- Are designed to provide a price signal around future investment **in the shared network** that links the price paid by a customer to their particular characteristics[7]. This is in contrast to the Interconnection Charge that is currently applied where any such price signal is muted because charges for investments are smeared across all load customers, so any one customer would pay very little of the cost of any particular investment;

7 That said, because the deeper-connection charge is only applied in situations where the HHI index is relatively high, it will not create a price signal where the HHI index of flows is low, which in theory, could lead users to want to locate in the denser part of the grid where the HHI index is more likely to be low. As a result, the decisions of some generation and direct connected parties about whether to expand or where to connect may be altered. However, our view is that the likely inelastic nature of locational responses by customers, particularly distribution businesses, to transmission price signals will mean this will not be a material effect and therefore, we have not specifically quantified this as part of this CBA

- Change the way historical investments will be recovered from existing customers, with both options still retaining a "residual charge", as currently occurs under existing pricing arrangements (eg, via the 'Interconnection Charge'), however both options:
  - would result in Transpower generating less revenue from this residual charge, relative to the revenue raised from the Interconnection charge, and
  - would reflect a materially different charging parameter (physical capacity), relative to the current arrangements (which are based on a measure of a customer's regional coincident peak demand).
- Are to be complemented by a more comprehensive PDP, relative to the current arrangements.

5. Framework for undertaking this CBA

The CBA has been developed in accordance with the broad framework set out in the Authority's CBA working paper ("Transmission pricing methodology: CBA Working paper 3 September 2013"). We have assessed the benefits and costs of the proposal in terms the Authority's statutory objective and, more specifically, the framework that it uses to interpret that objective ("Interpretation of the Authority's statutory objective, 14 February 2011").

In relation to the former, the key features are that we:

- Have sought to clearly define the economic objective – based on guidance from the Authority - that the new pricing options are attempting to solve, which in turn underpins the analytical framework that we have adopted;
- Have modelled the benefits and costs of the options that the Authority has selected and which it required us to assess;
- Have specified the baseline scenario against which the two proposed transmission pricing options have been assessed, which, for the purposes of this CBA, is the TPM that will operate from April 2017;
- Identified the *economic* impacts of the options, and where possible, quantified those impacts, which is discussed in a latter sections of this report;
- Calculated the results of the CBA;
- Analysed the sensitivity of the results to changes in key parameters; and
- Documented the results in this report.

In assessing the benefits and costs of the proposal in terms the Authority's statutory objective and the framework that it uses to interpret that objective, the Authority interprets its statutory objective as requiring it to exercise its functions in section 15 of the Act for the long-term benefit of electricity consumers and particularly that it[8]:

8 Electricity Authority, "*Interpretation of the Authority's statutory objective*", 14 February 2011, page 8

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;

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

increase the efficiency of the electricity industry, 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.

To this end, our interpretation is that the Authority must focus on economic efficiency, as opposed to the distributional impacts (ie, wealth transfers) that might stem from a change in transmission pricing arrangements (unless they impact upon efficiency). We have adhered to this approach when developing this CBA.

6. Caveats

6.1. General caveats

A CBA of changes to transmission pricing is inherently difficult in that a significant proportion of the likely benefits will be related to investment and dis-investment activities - dynamic efficiency benefits. Benefits may accrue from more efficient decisions affecting the type, timing, location and level of investment.

These are complex real world decisions and are influenced by many factors including, but not limited to, the costs of electricity and the relative economics of investments that substitute for transmission investments. Therefore, it is important to understand and estimate what responses may occur as a result of the change in transmission pricing.

However, it is beyond the scope of this work to model the specific investment options and price responses of every individual participant in the NZ electricity market who would be affected by a change in the way transmission services are priced. Instead, OGW has analysed the likely responses of different types of participants, as opposed to each individual participant. These participants are broadly categorised as follows[9]:

- Electricity distribution businesses;
- Directly connected load customers; and
- Generators.

We have not directly approached individual affected parties to obtain information that may have assisted us in undertaking this analysis. Instead, we have placed significant reliance on, in order:

- Publicly available information pertaining to the NZ electricity market, wherever possible;

9 This document refers to these participants as Transpower's "customers" throughout this document.

- Information provided by the NZ Electricity Authority;
- Publicly available information from other electricity markets, where we were unable to source information directly related to the NZ market; and
- Internal estimates from OGW's subject matter experts.

More broadly, it is important to note we have also needed to make a number of assumptions to prepare this CBA. In particular, a number of elements of the CBA are inherently difficult to quantify, in particular volumetric impacts on demand and assessment of the degree to which generation and transmission and generation will be more efficiently located and timed over 20 years (the analysis time frame). There is therefore uncertainty around the absolute level of benefit, which reinforces the need for sensitivity testing. However, the purpose of a CBA is to test if benefits outweigh costs and in this analysis the costs are relatively small and benefits range from moderate to significant but in all cases exceed costs by a significant margin.

6.2. Future expenditure levels that will be signalled to end customers by the new pricing arrangements

A fundamental issue that will affect the benefits of any transmission pricing arrangement is the level of future expenditure that will be signalled to end customers by the new pricing arrangements. Everything else being equal, a price signal from a new pricing arrangement will be less effective from an economic perspective when the pool of future investments covered by the price signal is smaller and when the proportion of future capital expenditure that *can* be influenced as a result of customers changing their future consumption or investment behaviour is smaller.

Therefore, when undertaking this CBA, we have had to make assumptions regarding:

- The overall quantum of future investment that will be signalled via the new pricing arrangements; and
- How much of that future investment expenditure would actually be able to be changed as a result of customers changing their future consumption or investment behaviour in response to that price signal.

The latter issue is discussed in more detail in the section that outlines our economic objective.

Predicting the quantum of future investment that both options will apply to will depend on a range of factors, not the least being:

- The level of future investment Transpower has to make in response to the *actual demands* customers place on its network with this investment also a function of where those demands occur;
- The level of future investment that Transpower will have to make to replace existing and future assets; and
- Transpower's ability, under the new transmission pricing options, to allocate the costs of those investments to particular customers.

Given this uncertainty, as a baseline, we have relied on information from the Electricity Authority as to the estimated level of demand-related capital expenditure Transpower will need to incur in the future to meet future levels of peak demand.

From this baseline, it has been necessary to make some general assumptions with regard to how much of that baseline expenditure might be captured under the two proposed pricing options. These assumptions are based on a qualitative assessment of the likely coverage of both options as a project-by-project assessment of the impact of the options was impractical - this is discussed in more detail in later sections of this report.

7. Overarching conceptual framework underpinning our assessment

7.1. Overview

It is important to describe the likely incremental efficiency benefits from moving towards more cost-reflective transmission pricing.

At a conceptual level, when the *marginal price* (being the change in a customer's charge due to a change in demand) for a service deviates from its *marginal cost* of supply, customers (being Transpower's load customers and generators, in the case of transmission pricing) will consume either:

- too much of the service attribute, which will occur if the marginal price is less than its true cost (eg, consumers or generators may connect or operate in a manner that consumes transmission services, despite the fact that the cost of providing them with an additional unit of that service attribute exceeds the benefit that they receive from consuming the additional unit); or
- less service than would be efficient, which will occur if the marginal price is greater than its cost of supply (eg, some customers will NOT consume transmission services, despite the fact that the cost of providing them with an incremental unit of that service attribute is less than the incremental benefit that they would receive from consuming that additional unit).

The more inelastic[10] the use of a product is to changes in price, or the smaller the difference between the actual price and cost reflective price, the smaller will be the loss in economic efficiency from adopting prices that are not cost reflective. In the unlikely situation that the demand for a service attribute is perfectly inelastic (the demand curve is vertical) then there is no 'deadweight loss' associated with adopting a price that deviates from the true marginal cost of supply of that service attribute.

Following on from the above, improvements in economic efficiency do not automatically follow from a move to more cost reflective prices. Rather, **economic efficiency is only improved if the benefits exceed the administrative and implementation costs required to move to that more cost-reflective pricing regime.** Put another way, cost-reflective pricing can be seen as a necessary but not sufficient condition for efficient decision making as there has to be an ability and likelihood that the price will be responded to.

10 An inelastic product is one where for any percentage change in price, there is a smaller percentage change in demand.

Notwithstanding the above, in assessing the efficiency gains or losses from a change in a transmission pricing structure, it is important to also consider more than just the impact that the *marginal price* signal has on consumption and investment decisions. This is because the underlying cost structure of a transmission network is such that the marginal cost is typically less than the average cost. As a result, the marginal price signal must be augmented to allow a transmission business to recover its 'residual costs' (being its total efficient costs, *less* the revenue generated from levying cost-reflective variable tariffs upon generators and load customers). It is important that the recovery of residual costs is done in a manner that least distorts consumption and investment decisions. In theory, these residual costs should be recovered via charges that do not vary with a customer or generator's marginal consumption decisions, for if they weren't, the marginal price borne by a customer for that consumption would deviate from the marginal cost of serving that consumption, thus leading to inefficient outcomes. However, in practice a trade-off between the impact on investment and consumption is often needed and should be informed by an understanding of willingness to pay. For example, the price should not inadvertently incentivise a customer or generator to inefficiently remain connected to, or disconnect from, the transmission network.

7.2. Key facets of the proposed price signal relevant to the achievement of the economic objective

This section of our report discusses a number of specific issues that we have explicitly considered when determining whether the proposed price signal is likely to further the achievement of the economic objective. Key issues include whether or not:

- The price signal results in there being a clear link between the actions of a customer, and the transmission prices that they face;
- The pricing of historical investments will affect economic efficiency, and therefore the results of this CBA;
- The pricing of certain types of future investments such as replacement expenditure and safety expenditure will contribute to improvements in economic efficiency, and therefore the results of this CBA; and
- The price signal would create indirect benefits via increased scrutiny of all new transmission investments leading to improvements in investment efficiencies.

At the end of this section, we have defined the economic objective that the transmission pricing arrangements are designed to solve, which in turn has underpinned our modelling approach and a number of the detailed assumptions supporting that modelling.

7.2.1. Marginal price signal versus overall price signal

Technically, the Authority's deeper connection-based proposal does not send a cost-reflective *marginal* price signal to end customers[11] with regards to the impact that their incremental consumption and demand behaviour will have on Transpower's future costs. It is noted that the Authority's AoB charge would however, involve Transpower sending a marginal price signal, as part of its broader AoB price signal. The latter is preferable, from an efficiency point of view – particularly in the context of a transmission business, which tends to exhibit significant economies of scale (which means that the difference between the average and marginal price can be material).

However, both the AoB charge and the deeper connection-based charge would lead to the costs of an eligible investment being recovered *after* the investment is made. However, in our opinion, this doesn't necessarily dilute the effectiveness of the original price signal, as long as customers:

- Understand there is a clear link between their actions and the incurrence of those future cash flows, prior to them undertaking the action;
- Are sent the price signal with enough lead-time such that they are able to make the necessary changes in their own investment or consumption behaviour in response to that price signal, and have these changes flow through to the costs Transpower incurs; and
- Are not incentivised to change their behaviour after the investment has been made, in order to change the future stream of payments that they must make so that Transpower can recover the costs of that investment (that is now already made).

For the purposes of this CBA, based on the information provided by the Authority, both of the proposed transmission pricing options in our opinion, appear to meet these threshold tests[12]. If any of these factors do not hold true, the benefits described and quantified in this CBA will exceed those that will occur in practice.

7.2.2. Pricing arrangements designed to recover the cost of historical investments

Notwithstanding the above, changing the way transmission services are priced will only improve economic efficiency if it influences a customer's future consumption and investment decisions and reduces Transpower's or other electricity industry participant's future costs.

To this end, the options proposed by the Authority appear to countenance applying the new pricing arrangements to the recovery of both future investments and historical investments. Subject to two provisos, the way in which historical investments are recovered should not materially influence economic efficiency, as these costs have already been incurred, and

11 For example, it doesn't involve sending a $/MVA variable price to customers that reflects the forward-looking costs that Transpower will incur in providing customers with additional future transmission capacity.

12 The fact that under the deeper connection-based charge, prices are effectively recalculated based on a five year rolling average of consumption may pose a slight risk to this. This is discussed in more detail in later sections of our report.

therefore, cannot be reversed. The two provisos[13] are that the recovery mechanism minimises the extent to which it:

- Distorts the future usage of the existing network (eg, consumption decisions); and
- Lead customers (including generators and distributed generators) to make inefficient connection, disconnection or other investment decisions.

The impact that the recovery of historical investments can have on future consumption decisions

If the recovery of historical investments[14] is achieved via a charge that is linked to a customer's actual demand or consumption, then:

- Customers, in theory, have an incentive to reduce their demands/consumption in response to that price signal; *yet*
- Any reduction they make to their demand / consumption will not change the historical costs that this charge is primarily designed to recover.

This is why, in theory, these residual costs should, ideally, be recovered via the levying of charges that do not vary with a customer or generator's marginal consumption decisions (so that users do not have an incentive to alter their use to inefficiently avoid the charge[15]).

On face value, the current Interconnection Charge, which recovers all of Transpower's TPM costs that are not recovered through the HVDC charge or connection charges, appears to recover historical costs via a charge that is linked to a customer's actual demand. In particular, the basis for levying the current Interconnection Charge is a measure of a customer's regional coincident peak demand (RCPD), therefore, on face value, this will incentivise customers to reduce their demands in response to that price signal (yet any reduction would not change the historical costs that this charge is primarily designed to recover).

However, despite this, it is noted that:

- A customer's regional peak is calculated over multiple trading periods – 12 for the Upper North Island (UNI) and Upper South Island (USI) regions[16], and 100 for Lower North Island (LNI) and Lower South Island (LSI); and

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13 A third potential issue is if not charging customers for past investments that were made for their benefit creates a time consistency problem (ie, if users are forgiven the debt they "owe" on historical assets), they will expect there is some chance that the debt will be forgiven on new assets once they are built, and act accordingly, thus undermining future investment efficiency. However, the assumption we have made when formulating this CBA is that the rules underpinning the future pricing of transmission services will make it clear that this will not be the case in the future, thus reducing this risk to immaterial levels (despite this being allowed under a previous transmission pricing arrangements).

14 For the avoidance of doubt, we are not referring to future costs that may stem from those historical investments (eg, operating and maintenance costs)

15 Whilst this is theoretically correct, in the absence of information about different customers' willingness to pay, some have argued (eg, Laffont &Tirole, *A theory of incentives in procurement and regulation (1994)*, p.145-9) that the optimal two-part tariff would trade-off distortions to disconnection decisions against distortions to consumption decisions.

- If, in Transpower's view, there are exceptional circumstances that have led to distortions in the RCPD, the Code allows Transpower to adjust the RCPD quantities to minimise the distortion.

Taken collectively, these factors contribute to a slight reduction in the degree to which end customers will respond to the Interconnection Charge in a way that diminishes economic efficiency. This is reinforced by the changes that are proposed to be made from the pricing year starting 1 April 2017[17]. Nevertheless, the charge will still be based on use and so will continue to distort that use.

In addition to the Interconnection Charge, Transpower currently applies a HVDC charge[18], which is designed to recover the (predominately historical) costs of the HVDC link that operates between the North Island and South Island. In simple terms, this charge is based on each South Island generator's averaged historical anytime maximum injections (HAMI) over a specified period. However, it is our understanding that the allocation of the costs of the HVDC link will change from this peak injection charge (HAMI) to a mean injection charge termed the South Island Mean Injection (SIMI) charge.

On face value, the current HVDC charge would appear to have some similar features to the Interconnection Charge, in that it is recovering the historical investment made in the HVDC link via a charge that is in fact linked to a customer's actual injection (ie, marginal decisions). On face value, this would incentivise generators to reduce their injections in response to that price signal (yet any reduction in injections in response to the price signal would not change the historical costs that this charge is primarily designed to recover). Moreover, it could incentivise future generators to locate in the North Island so as to avoid this charge, yet we have not seen any evidence to suggest that such a decision would materially impact on Transpower's future costs associated with the HVDC network (and it may lead to increased costs of augmenting the Transmission network in the North Island, for which there is currently no price signal).

Impact that the recovery of historical investments has on future connection decisions

Notwithstanding the above, even if the recovery of historical investments is achieved via a charge that is not linked to a customer's actual demand or consumption, it will not automatically mean that the pricing of historical investments will lead to efficient outcomes.

The pricing arrangements need to ensure that in totality, these charges do not inadvertently incentivise a customer or generator to inefficiently connect to, or disconnect from, the transmission network. To be clear, the emphasis is on industry-wide efficiency and the trade-off needed to create a workable tariff (discussed earlier) which may necessitate some

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16 It is our understanding that this will be changed to 100 trading periods from the pricing year starting 1 April 2017. Furthermore, it is our understanding that the Capacity Measurement Period (CMP) will also exclude the months November - April for the Upper North Island (UNI), lower North Island (LNI), and Lower South Island (LSI) regions from that date onwards.

17 https://www.transpower.co.nz/sites/default/files/plain-page/attachments/TPM_Operational_Review_Approvals_Aug2015.pdf

18 Chapter 6 of the Consultation Paper provides further discussion of the economic efficiency effects of the HVDC charge.

consumption related element. In this context, the pricing arrangements must lead to charges that are:

- Below the stand-alone cost of serving a load customer or generator – with the stand alone cost reflecting the opportunity cost to that load customer or generator of staying connected to the grid, and
- Above the incremental cost of serving that load customer or generator.

In basing its current charges on a measure of a customer's demand (the "Interconnection Charge") or injection into the transmission grid ("HVDC charge"), Transpower is, in our opinion, creating a charging framework that is unlikely to systemically lead to customers facing charges above their physical standalone cost. In particular, a key driver of the cost of any economic alternative to the transmission network will be demand. This alignment therefore reduces the risk that the overall level of revenue recovered from a customer will materially mis-align with an alternative, physical connection. This is further supported by the fact that the current Interconnection Charge is also supported by the PDP that allows Transpower to provide a prudent discount in order to avoid incentivising inefficient by-pass of existing grid assets. However, it will not necessarily ensure that charges are less than a customer's overall willingness to pay to retain a connection to the transmission network, which may lead to inefficient outcomes if transmission prices:

- Exceed a customer's willingness to pay for transmission services; but which
- Are greater than the costs Transpower would avoid if they ceased to supply that customer with transmission services.

Benefits of the two alternative options, with regards to the pricing of historical investments

Conceptually, the two alternative options have some attractive features, relative to the current approach to pricing transmission services, in particular:

- The proposal to base the recovery of residual costs on a measure of physical capacity, instead of the RCPD would, in our opinion, be a means of recovering historical costs in an equitable manner without materially influencing future consumption, generation or investment decisions;
- The adoption of either of the two proposed options to recover historical investments would link the recovery of some historical costs to an assessment of either who has benefited from the construction of that asset (AoB) or a measure of the concentration of flows related to that asset (deeper connection charge), both of which, to our mind, would reduce (but not eliminate) the risk that prices will breach the stand alone and incremental cost tests,

- The AoB charge provides for the potential re-estimating of the beneficiaries of the historical investment if there is a material change in circumstances, whilst the deeper connection-based charge is based on a 5-year rolling average of consumption – so if the beneficiaries change over time[19], the allocation of the historical costs could also change to reflect this, thus limiting the likelihood that there will be a disconnect between the benefits obtained by a customer, and the charge to them (which is the situation which is most likely going to lead them to inefficiently disconnect from the grid); and
- Both approaches are being complemented by the introduction of an even more comprehensive PDP, which provides a further means for Transpower to adjust its charges to these customers so as to ensure that those customers subject to the AoB charge or deeper connection-based charged do not inefficiently disconnect from the network.

Types of future investments that contribute to improvements in economic efficiency

The Authority appears to countenance applying the new pricing arrangements to the recovery of all types of future capex (eg, capacity, reliability, replacement, refurbishment).

It is important to identify whether the pricing of all of these types of capital expenditure will directly lead to material improvements in economic efficiency. Put more succinctly, there is no economic benefit from Transpower developing a price signal to signal the future costs of providing certain services, if their (or other electricity industry participants') costs will not change as a result of end customers responding to that price signal.

To operationalise this concept, we asked ourselves:

> *If a cost is included in the development of a forward-looking price signal, which customers would be incentivised to respond to, and in fact do respond by either changing their behaviour or through their subsequent decisions regarding where, when or how they invest in the assets in the electricity supply chain, will that response actually reduce Transpower's or any other party's future costs?*

If the answer is no (eg, costs do not change, even if customers do respond), then there will be no economic benefit stemming from sending a price signal to that customer.

Having regard to the above, we have proceeded on the basis that that there would be an economic benefit in reflecting the following costs in any forward-looking price signal:

- **Forecast augmentation capital expenditure:** As future changes in customer demand can affect the timing and size (and therefore cost) of any expenditure in this cost category, and customers may be able to alter their investment decisions in response to the pricing of this cost driver; and

19 Although as discussed earlier in the report, this can have an impact on economic efficiency if customers are (a) incentivised to change their behaviour after the investment has been made, in order to change the future stream of payments that they must make so that Transpower can recover the costs of a historical investment, or (b) this increases the commercial risks to transmission customers, thus leading a higher risk premium being applied to transmission investments.

- **Incremental forecast operating and maintenance expenditure related to a change in demand or energy consumption:** As future changes in customer demand and consumption are likely to drive a small amount of its future operating expenditure (eg, maintenance costs associated with capacity driven capex).

This means that our starting point is to exclude the following costs from our analysis:

- **Forecast corporate, safety related and IT capital expenditure costs:** As the timing and scale of these costs will not be affected by changes in future customer demand or energy consumption;
- **Historical investments:** Subject to these costs being recovered in a way that minimises the extent to which they (a) distort future industry-wide usage or investment decisions (eg, consumption or investment decisions) or (b) lead customers to make inefficient connection or disconnection decisions, the recovery of these costs will not impact upon economic efficiency; and
- **Non-incremental forecast operating expenditure:** As this expenditure will not be influenced by future changes in demand or consumption. This includes costs related to areas such as Finance, Regulation etc.

The material area of capital expenditure where we believe that there is some uncertainty around whether or not there will be a material economic benefit from sending a price signal that is linked to future expenditure is for asset replacement.

On one hand, our experience is that the efficient *timing* of an electricity network's **forecast replacement expenditure is** generally not materially affected by the demands (or behaviours) that are placed on their network by end customers[20]; rather, it is predominately driven by condition and risk factors unrelated to the loads (or behaviours) placed on the asset. This means that the efficient timing is unlikely to be materially influenced by end customer behaviour. The role of the regulatory framework is critical in this matter and is discussed further in the next section.

On the other hand, the sizing and other technical features of the replacement solution *may* be influenced by the decisions and behaviours exhibited by downstream parties. For example, the sizing of a replacement transformer is likely to be linked to the demands expected to be placed on that transformer. However, the benefit, in this context, is the incremental change in costs between the "fully" sized transformer, and the "downsized"

20 In saying this, we have assumed that the timing of Transpower's replacement expenditure will generally be driven by *Transpower's assessment* of the forward-looking operating and maintenance costs of continuing to operate an existing asset, as well as the probability times consequence of that asset failing. Operating and maintenance costs are predominately a function of maintaining the availability of the asset, not energy throughput or peak demand. The probability of an asset failing is almost de-linked from the end-customer behaviour, rather, it is a function of age, condition, location and other factors that affect its useful life. The consequence of failure is a function of the attributes of the customers served by that asset, as well as other features of the design of the network in that area that may allow load to be switched and served by other parts of the transmission network (or distribution network). Overall, none of the factors driving the efficient replacement of an existing, in situ transmission asset, is likely to be able to be materially influenced by end customer behaviour in our opinion. Further, there are unlikely to be any feasible economic alternatives to replacing existing assets. For example, the economics of permanent embedded generation as an alternative to a centralised (generation, transmission) is limited.

transformer, which will be significantly impacted by the economies of scale (or the loss thereof, in this case) associated with making that investment. This diminishes the likelihood that an alternate option is likely to be an economically feasible alternative to the replacement of an existing asset.

7.3. Creation of increased scrutiny of new transmission investments, which will lead to improvements in transmission investment efficiencies

As we understand it, the regulatory framework charges the Commerce Commission[21] with assessing Transpower's proposed capital expenditure program. This includes both "base" capex, covering, in most cases[22], all replacement and refurbishment (R&R) capex and enhancement and development (E&D) below a cost threshold set by the Commerce Commission (currently set at $20m), and major capex, which is all E&D capex above the threshold, and expenditure on non-transmission solutions.

Transpower also faces incentives to reveal its efficient costs during the regulatory period. This would result if the financial benefit to Transpower from out-performing its capital expenditure forecasts under the existing regulatory incentive scheme (ie, the incentive to reveal its efficient costs) exceeds the potential for Transpower to roll-in its actual capital expenditure into its Regulatory Asset Base, and thus, earn a return on and of that investment over the life of the asset. The extent to which this incentive is effective will depend on various factors, including Transpower's financial position (eg, cashflow and gearing) at the time the investment is being contemplated and, more importantly, whether the regulated WACC is materially higher than Transpower's actual WACC[23]. On the balance of probabilities, the regulated WACC is likely to be the higher than Transpower's actual WACC, given our understanding that the Commerce Commission has adopted a WACC allowance at the 67th percentile. Our high-level analysis indicates that the regulated WACC must exceed Transpower's actual WACC by around 2.5%[24] or more for there to be a financial incentive for Transpower to not reveal its efficient costs during the regulatory period. That said, we are unable to say whether or not this is likely to be the case.

Everything else being equal, this process is designed to:

- Provide a third party assessment of Transpower's proposed capital expenditure forecasts; and

21 This is not to say that the Commerce Commission adopts the same procedures and processes to scrutinise each of Transpower's proposed investments. For example, presumably, the Commerce Commission would not undertake project-by-project scrutiny of smaller investments.

22 We have been informed that the capex Input Methodologies leaves open the possibility that not all replacement and refurbishment capex would be covered by the Commerce Commission's base capex regime.

23 The opportunity cost to a regulated business of making an efficiency saving is the foregone excess returns (ie, the return a business achieves, after paying risk adjusted market returns to debt and equity holders for the use of their funds) that it would have achieved had it spent that money, and rolled it into its regulated asset value. The opportunity cost therefore reflects the difference between their regulated WACC and their actual WACC, not the WACC itself.

24 To be clear, this means that if Transpower's actual WACC was 7%, then the regulated WACC would need to be 9.5%.

- Incentivise Transpower to reveal its efficient costs during the regulatory control period[25].

Notwithstanding the above, a benefit could arise from the introduction of either pricing option if they were to lead customers to scrutinise[26] Transpower's proposed suite of investments in more detail, in particular, to assess whether those investments were consistent with their willingness to pay for the services that are provided as a result of those investments.

More particularly, better information regarding customers' willingness to pay for transmission services might lead to Transpower adopting a more efficient transmission investment program[27]. Customers have a greater incentive to reveal their willingness to pay when their charges are more directly related to new investments that they benefit from and this is likely to prompt customers to more actively engage with the process for approval of investment.

On face value, this has merit, as currently, few customers have a "vested interest" in revealing their willingness to pay, nor to scrutinise the projects being proposed by Transpower, quite simply, because the cost of any project is effectively spread across all customers under the current pricing arrangements. On this note, we have been informed that there have been anecdotal reports that some customers would have more actively engaged with Transpower, had they faced this price signal, and moreover, that they may have revealed their preferences for an alternative investment solution, had they have been charged the full cost of a transmission investment.

Transpower's customers are of course unable to require that Transpower spend money replacing or augmenting assets the costs of which would be smeared across all customers. However, if customers do not face the cost of investments, they have a greater incentive to lobby Transpower to seek uneconomic investments that they benefit from. Agency theory suggests that Transpower has an incentive to adjust its actions to some extent to take account of the wishes of its customers.

Therefore, on face value, this benefit is inextricably linked to the robustness of the regulatory regime, the Commerce Commission's enforcement of that regulatory regime, and the extent to which the regulated WACC received by Transpower's exceeds its actual WACC by around 2.5% -- all parameters that we are unable to reasonably quantify. As a consequence, we have incorporated the benefit from increased scrutiny as an unquantified benefit, and undertaken sensitivity analysis to indicate its possible magnitude. This is a conservative assumption. Importantly the CBA is positive under this conservative position.

25 This is not to say that Transpower is not incentivised to propose higher levels of capital expenditure than it may otherwise reasonably require, and then seek to outperform its capital expenditure allowance (ie, to reveal its efficient costs)

26 Scrutiny, in this context, will not overcome the issue of asymmetric information – that is, Transpower having more or superior information compared to the Commerce Commission and its customers in relation to the assets that it currently uses to provide those customers with Transmission services, as well as any new augmentation options/solutions that may allow them to provide services in the future.

27 This includes all forms of transmission investment, including capacity (augmentation) related expenditure, replacement and refurbishment expenditure.

7.4. Conclusion – Economic Objective

For the purposes of developing the quantitative aspects of the CBA, the Authority has stated that the overarching *economic* objective of any transmission pricing arrangement is to maximise:

> *the overall efficiency of the electricity industry for the long-term benefit of electricity consumers. Overall efficiency refers to both efficient use of the grid and efficient investment in the electricity industry – the grid, generation and demand-side management.*

Given the discussion outlined in the previous sub-sections of this chapter, we have:

- Assumed customers:
  - understand there is a clear link between their actions and the incurrence of those future cash flows, prior to them undertaking the action;
  - are sent the price signal with enough lead-time to enable them to make the necessary changes in their investment or consumption behaviour in response to that price signal, and have these changes flow through to the costs Transpower incurs; and
  - are not materially incentivised to change their behaviour after the investment has been made, in order to change the future stream of payments that they must make so that Transpower can recover the costs of that investment (that is now already made).
- Assumed that the two options would, if anything, improve economic efficiency as it relates to the pricing of historical investments. In particular, we have quantified the potential for the current:
  - RCPD charge to lead to inefficient future investment decisions by distribution businesses or other parties under the base case (eg, investment in distributed generation or demand response for the purposes of reducing the RCPD related component of the transmission bill, without a corresponding reduction in transmission costs);
  - PDP arrangements to lead to inefficient disconnection of large direct connect customers as a result of the current charges (a) exceeding their overall willingness to pay to retain a connection to the transmission network, but where (b) their willingness to pay exceeds the costs that Transpower would avoid if that customer ceased being supplied with transmission services; and
  - HVDC charging arrangement (ie, the South Island Mean Injection charge) to lead to inefficient future investment in generation assets.
- Not ascribed any potential economic benefit to replacement expenditure in the base CBA, but to assess this via sensitivity analysis (in the form of how much future capital expenditure will be subject to additional scrutiny as a result of the pricing options); and
- Not explicitly quantified the potential economic benefits from the additional scrutiny of Transpower's investment decision (including replacement expenditure) in the base CBA, but rather, we have assessed this via sensitivity analysis. This is based on our understanding that this benefit is inextricably linked to the robustness of the regulatory regime and the Commerce Commission's enforcement of that regulatory regime, which is a parameter that we are unable to reasonably quantify.

8. Benefits modelled

8.1. Introduction

Building upon the discussion in the previous sections, OGW has conceptualised a number of different potential benefits stemming from a change in the way transmission services are priced. These include that the new price signal may lead to more efficient:

- Future investment in services or equipment that may otherwise be substitutes for future transmission services, thus leading to a reduction in the overall cost of providing electricity services to end customers;
- Future investment in electricity generation services, after accounting for the impact that the sizing, location and timing of generation investment has on future transmission investments, thus leading to a reduction in the overall cost of providing electricity service;
- Pricing of historical investments made in the transmission network (including the ability to change these prices as a result of the PDP), with this leading to:
  - More efficient investment decisions by distribution businesses or other parties as a result of the removal of the RCPD charge;
  - A lower probability of some customers inefficiently exiting the grid; and
  - More efficient future investment in generation related assets.
- Quantities of services being demanded by the market, thus leading to a reduction in the overall cost of providing electricity services.

These are discussed in more detail below.

8.2. Future investment in services or equipment that may otherwise be substitutes for transmission services

8.2.1. Background

The demand for transmission services will be a function of:

- End customers' willingness to pay for these services, which in turn will in part be a function of the cost of services; and
- Load customers' (eg, distribution businesses) ability to substitute transmission services for other services that will allow them to meet their customers' demands at the lowest economic cost.

The former is discussed in a later section of this report. In relation to the latter, at one extreme, if load customers have no feasible economic substitute to the services provided by Transpower's transmission network, then moving to more cost-reflective pricing of transmission services will not change the level of transmission investment, given a certain level of demand. Put another way, the same transmission investments (eg, timing, location, sizing) will occur, for any given quantity demanded. In this case, the demand for transmission services would be perfectly inelastic.

At the other extreme, if one or more load customers could feasibly make one or more alternate, economically feasible, investments, as a substitute for an investment in a transmission service, then the way transmission services are priced to load customers may change the level of transmission investment demanded. Put another way, different investments (eg, timing, location, sizing, type) may occur for any given quantity demanded. In this case, the demand for transmission services would not be perfectly inelastic.

To account for this we have conceptualised the generic options that load customers such as electricity distribution businesses may be able to avail themselves of as a substitute to a transmission investment, particularly as a substitute for investment that is driven by peak demand.

Our experience is that these options may include:

- Generation, embedded within the distribution network,
- Energy storage, embedded within the distribution network, and
- Demand-side response.

The role of demand side is confirmed by Transpower on its website, when it states that[28]:

> *Managing peak demand levels is an alternative to transmission investment. There may be a situation where we forecast that the network will need new investment in five years because electricity demand in the region is predicted to grow substantially. We could defer this investment if we use demand response at peak times, slowing down the peak load growth in a region. Less transmission infrastructure means lower electricity costs for end consumers*

Transpower goes on to state that[29]:

> *Any reduction in peak demand can result in reduced grid and generation investment. Less transmission and generation infrastructure means lower electricity costs for end consumers.*

8.2.2. Methodology used to model benefits

The following table summarises our assessment of the annualised LRMC (using the Average Incremental Cost approach[30]) of providing transmission services to the different regions for load customers and generators. Only the Scenario 1a result – which is based on information provided by the Authority and is assumed to reflect the most realistic forward-looking demand-driven investment programme - has been used in the base CBA where a load LRMC is required to undertake a calculation. Scenario 1a and 1b generation LRMCs have been used to calculate two separate amounts for the benefit stemming from the co-optimisation of transmission and generation – which, as discussed elsewhere in this report, have been averaged under our base case.

The results of the load LRMC for the low investment scenario has been used for sensitivity analysis. The approach to developing these results is detailed in Appendix A.

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28 https://www.transpower.co.nz/about-us/demand-response/benefits-demand-response [accessed 19/11/2015]

29 Ibid

30 The Average Incremental Cost approach reflects the NPV (future capex and opex) / NPV (cost driver), with the latter being peak demand (MW).

Table 3: LRMC of transmission services

Category of LRMC	Estimated annualised $ / MW		
Load Customers	**Scenario 1a - Huntly stays ($1.2b over 20 years)**	**Scenario 1b - Huntly leaves ($1.5b over 20 years)**	**Low Investment[31] ($750m over 20 years)**
Lower South Island	$50,429	$69,842	$34,921
Upper South Island	$20,103	$27,842	$13,921
Lower North Island	$27,937	$38,691	$19,346
Upper North Island	$44,237	$61,266	$30,633
Generation	**Scenario 1a Huntly stays ($800m over 20 years)**	**Scenario 1b - Huntly leaves ($1b over 20 years)**	**Low Investment ($500m over 20 years)**
Lower South Island	$51,301	$71,049	$35,525
Upper South Island	$23,678	$32,793	$16,396
Lower North Island	$48,859	$67,668	$33,834
Upper North Island	$35,949	$68,142	$24,894

Source: OGW estimates of the $/MW are based on OGW's analysis of capex and demand information provided by the Electricity Authority. OGW has used its professional judgement to make adjustments for the amount of non-shared network demand driven capex in the load related capex forecasts underpinning its LRMC calculation. It has also made downward adjustments to account for the fact that its analysis has been undertaken over a 19-year horizon (due to data availability), yet these assets generally have lives of around 50 years. These adjustments are discussed more in Appendix A.

The above results are based on OGW's analysis of forecasts of demand-driven capex and peak demand provided by the Authority. The LRMC figures for load are relatively consistent with LRMC estimates for other transmission businesses. For example, the Australian Energy Market Operator (AEMO) is required to develop TUoS locational prices based on the LRMC for the Victorian electricity transmission business.[32] These figures range from around $14,000/MW (AUD) through to $52,000/MW (AUD) depending on the region, with an average of around $25,000/MW (AUD)[33].

31 Note that the low investment program is assumed to be able to meet the same level of demand, hence the lower LRMC figures.

32 In its capacity as Transmission Network Service Provider in Victoria under that state's regulatory regime - which differs from other states where AEMO does not have this role.

33 AEMO, *Electricity Transmission Use of System Prices*, 15 May, 2013

The following table summarises our estimates of the annualised cost per MW[34] of implementing a number of feasible options[35] for managing peak demand levels, as an alternative to a transmission investment.

To be clear, there may be other potential benefits that a proponent of any or all of these options may be able to monetise, however, we have not attempted to model them for purposes of this analysis.

Table 4: LRMC of alternatives to transmission investments

Option	Estimated annualised $ / MW
Storage (constructed in 2015)	$581,310
Storage (constructed in 2025)	$263,524
Diesel Recip	$132,447
Natural Gas Recip	$181,615
Demand-side response	$19,605[36]

Source: OGW

The detailed assumptions underpinning the estimates in the above table are contained in Appendix B (embedded generation) and Appendix C (demand-side). However, the key assumptions underpinning the embedded peaking generation costs outlined above are:

- Only Li-Ion battery storage has been considered due to its emergence as the dominant technology for energy storage and the rapid decline in its cost;
- Storage capital costs are based on Lazard's levelised cost of storage analysis V1.0;
- Li-Ion battery experience curve and price forecasts are based on information published by Bloomberg New Energy Finance;
- Diesel and natural gas reciprocating generation capital and operating costs are based on OGW's experience and estimates;
- Diesel and gas pricing are based on statistics from the NZ Ministry of Business, Innovation and Employment; and

34 We have used the same approach to deriving these figures as we did the LRMC of the transmission network. We have assumed a 20-year life in most cases. More detailed information supporting these calculations can be found in Appendix B.

35 To be clear, we have not modelled every single alternative to a transmission investment that might be available to every single transmission customer. To be conservative, we have focused on options that are not reliant on the physical characteristics of the surrounding environment (eg, hydro, geothermal, solar), on the assumption that the most economic sites have already been identified and developed.

36 This is based on our assessment of the costs that Transpower has incurred in undertaking its current demand response program. More information on this can be found in Appendix C.

- It is assumed that the capacity operates 2% of the year.

The key observations regarding the above options are that:

- Transpower's historical expenditure on demand-side response (DR) appears to be relatively inexpensive, compared to all of the other options for balancing supply and demand. However, the:
  - market for DR is not infinite at current cost levels (although by no means does this mean it is likely to be exhausted either); and
  - DR may not necessarily be considered to be as reliable as a network solution (due to risks around their ability to respond in all situations).
- Despite significant discussion in the media regarding the potential for increased penetration of storage – both on the customer's side of the meter or on the grid side – our analysis indicates that it is not an economically feasible option when assessed purely in the context of providing capacity support services, both now, and in the medium term.
- Diesel reciprocating generators are, on face value, the most economic physical solution for providing capacity support, however, everything else being equal, they generally do not represent an economic long-term alternative to a network investment. That said, diesel generators do have a number of salient features that make them attractive in some circumstances:
  - Reciprocating generator sets have advantages where demand growth is small (up to approximately 30MW) and where there is some risk of the demand eventuating (for example, industrial applications such as mining which are dependent on commodity prices). Another advantage is the generator sets can be easily relocated and redeployed to new locations that may need support or deferment of network capital. Both attributes imply that there is a real option value associated with the use of solutions such as this (as compared to an inflexible solution such as a transmission augmentation). Everything else being equal, this increases the value of these types of investments, particularly when faced with a more uncertain future (eg, greater uncertainty around future demand forecasts);
  - Diesel generator sets are particularly adaptable as they can be completely self-contained in container style 1 to 2 MW modules that can be easily placed on a truck trailer for easy relocation. The modules include fuel tanks located in the floor. Natural gas generator sets, while also containerised or modularised, need to be located adjacent to a natural gas pipeline or an alternative gas source making the technology less flexible for the application of embedded support; and
  - Reciprocating generator sets are considered highly reliable and are used for backup generation for mission-critical applications such as data centres, hospitals and military applications.

It is important to note that embedded generation solutions such as those discussed above are generally only used to delay investments (as opposed to defray the need for the investment in perpetuity). This relates back to the option benefit that these flexible solutions provide a proponent.

The following case study illustrates how a transmission company in Australia implemented an alternative to a transmission solution.

Box: 1: Case Study - Powerlink

In 2013, the Queensland transmission network owner, Powerlink, entered into a network support agreement with independent power producer, Energy Developments (EDL) to provide embedded generation for the Bowen basin mining area. With growth forecast to increase within the region and a requirement for augmentation, Powerlink, investigated the merits of alternative approaches to setting planning standards and the non-network solution was in response to the economic imperatives to reduce network costs, and strong signals to take the costs and benefits to consumers into account in network development.

The cost-benefit analysis of seven options were considered as part of the regulatory test process which saw the option of a network support agreement for EDL, along with some lower cost augmentation, to expand their embedded waste coal mine generation plant in the region from 45MW to 57MW as the best economic solution.

Alternatives to transmission investment in the long-term

Collectively, the above information indicates that there may be feasible alternatives to transmission investments[37] for managing peak demand levels in some areas. To model this, we have:

- Assumed that given the likelihood that the transmission investment would be the preferable option due to its greater reliability, the most economic non-transmission investment (which is demand-response) would be subjected to a 15% premium (changing its break-even point from $19,605/MW, to $22,545/MW); however
- For regions where we have calculated a Scenario 1 LRMC higher than $22,545/MW, we have multiplied:
    - the annual increase in quantities in that region (ie, the quantities that underpin the LRMC result for that region); by
    - the difference between the LRMC for that region, less the annualised cost of the DR (being $19,605/MW), by

[37] We are also not aware of any other formal regulatory mechanism such as a regulatory investment test that applied to transmission upgrades that would facilitate the adoption of the least cost investment in these circumstances.

- the estimated percentage reduction in load that could *feasibly* occur as a result of the use of DR instead of the transmission investment. This is based on the assumption that DR (at these prices) is finite. This percentage (8%) is based on OGW's assessment of the available literature from other jurisdictions related to both actual and potential uptake of DR[38].

Alternatives to transmission investment in the short-term

In addition to the above, we have modelled the potential benefits of using an embedded generator (namely, diesel reciprocating generators) to defer a number of larger transmission projects over the evaluation period. More particularly, we have assumed that:

- There will be 5 large transmission projects (valued at $40 million each) that will need to be constructed to service load customers over the evaluation period, with an NPV of nearly $73 million (which represents, in NPV terms, less than 6.5% of the total capex that our modelling assumes will be spent over the evaluation period for the base case, hence this is considered relatively conservative);
- Each of these could be deferred by one year, via the use of a 10MW diesel generator[39];
- The economic benefit of that deferral is based on the carrying cost of the transmission capital expenditure for one year; and
- The (annualised) economic cost of delivering that deferral benefit is the: (a) upfront cost of purchasing that diesel generator, and (b) the operating costs associated with running that generator in each of the years when it will be used to defer transmission project.

8.3. Future investment in electricity generation services, thus leading to a reduction in the overall cost of providing electricity services

8.3.1. Background

The cost of providing generation services will be affected by numerous exogenous and endogenous factors, including, but not limited to the:

- Quantities of electricity demanded by the market;
- Level of reliability that is required to be provided to end customers;

38 For example, see AEMC, "*Appendices - Power of choice review - giving consumers options in the way they use electricity*", 30 November 2012 (section C5), which estimates the demand response in US electricity markets at on average 7.2% of total demand; the demand response capability in the Western Australian Market to be 8.2% of total demand; the demand response in the Commercial and Industrial sector of the Eastern Australian market to be between 6% and 8% of total demand. We also note that AusNet Services, a distribution business in Victoria, Australia, introduced a Critical Peak Demand tariff that has generated 102MW of demand response on a total peak demand of 1800MW (5.5%) - from approximately 2500 Commercial and Industrial customers. (http://www.aer.gov.au/system/files/AusNet%20Services%20Tariff%20Structure%20Statement%20proposal%20-%2026%20October%202015_0.pdf).

39 The sizing of the generator is based on our assessment of the scale of investment that would facilitate the deferral of a project by one year. This is based on the expected annual growth in MW in the NZ market that will drive individual transmission projects to occur.

- Availability of sites upon which new generation facilities can be placed;
- Availability of the underlying source of 'fuel' (eg, wind, solar, water); and
- Configuration of the network, as it relates to transporting energy from generation sources to load customers.

Taking demands and reliability as exogenous variables, the most economic supply of generation services will as a minimum, trade off the cost of:

- Generating the electricity; versus
- Transporting electricity to load areas.

The upfront and on-going costs of generating electricity is a cost that is already borne by the market participant generating that electricity and would not be directly affected by the way in which transmission services are priced.

However, the cost of *transporting* electricity will change, given the transmission pricing options that are being proposed. In particular, it is our understanding that:

- The current pricing arrangements result in there being a highly imperfect network price signal. An effective network price signal will lead new generators to co-optimise generation costs and transmission costs;[40] and
- Both new pricing options will signal the costs of some future assets deeper in the grid to generators that benefit from the construction of those assets.

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40 The HVDC is a network price signal affecting future generation, however, as discussed in other parts of this report, it is unlikely to be cost-reflective, and therefore, lead to efficient outcomes. Further, energy spot prices are determined at every location (or node) and prices vary around the grid due to transmission losses (ie, the energy market provides an efficient signal in respect of losses), therefore, this price signals the areas where congestion is occurring. Conceptually, this should lead generators to make efficient operating decisions in the short-run. However, due to the 'lumpiness' or scale of subsequent investment, the congestion component is likely to reduce significantly after an investment is made (this is sometimes described as the 'saw-tooth' effect). In this situation, the investment plans of generators (as opposed to their operating plans) are likely to assess the future probability of the congestion component of the energy price continuing or collapsing (as a result of a transmission investment to alleviate congestion). As the current pricing arrangements do not send a price signal to generators that benefit from that transmission investment, there is the potential for generators to 'see through' the short term price signal, on the assumption that the source of congestion will be alleviated in the future by a transmission investment. This may mean that a longer term price signal around future transmission investments may represent a more efficient long term price signal for generation investment.

Conceptually, both new pricing options will almost certainly lead to an improvement in economic efficiency[41], as they will lead new generators to factor the transmission costs linked to their investment decision into their business cases. This should lead prospective generators to consider both of these factors collectively, thus leading to more efficient outcomes. To be fair, generators may already consider the risk of congestion in their decisions but currently see no direct financial impact in transmission charges, which will be explicit under the proposed new arrangements. However, the magnitude of this economic benefit will be inextricably linked to the:

- The amount of new generation investment that is required to service forecast demand – everything else being equal, the lower the amount of new generation that is required (or the larger the amount of spare capacity), the smaller will be the benefit from sending a more cost-reflective price signal around transmission investment;
- Quantum (in terms of cost) of investment in transmission capacity that is required to be built in the future to service generation – everything else being equal, the smaller this value is, the less likely it is to influence the sizing, location and timing decisions of prospective generators (and hence the economic benefits of sending the price signal);
- The difference in the cost of future investment in transmission shared network capacity in different regions – everything else being equal, the smaller the difference in the future cost of providing shared network transmission services to generation customers in different geographic regions, the less likely it is that the transmission price signal will influence the sizing, **location** and timing decisions of prospective generators (eg, it is less likely to lead to a relocation of generation from one region to another); and
- The slope of the supply curve for new generation capacity – everything else being equal, the steeper the production function, the less likely any transmission price signal will cause a change in the sizing, location, timing and type of new generation.

8.3.2. Methodology used to model benefits

OGW has assessed the effect of two different factors on the co-optimisation of generation and transmission investment. These relate to the:

- Amount of transmission investment that will be required in the future and which will be driven by generation requirements, and
- Whether a number of existing generation facilities (namely the Huntly Rankine units) are retained or not.

The former affects the LRMC of providing transmission services to service incremental increases in generation output in response to changes in electricity demand. The latter affects the level of spare capacity that is assumed to currently exist, and therefore, the amount of new generation that needs to be built to service increases in demand.

41 And the sending of the more cost-reflective price signal will almost certainly *not*, in and of itself, lead to a diminishment in economic efficiency, thus the lower bound economic benefit for this component of the CBA is assumed to be zero.

More specifically, OGW has utilised the following methodology to assess whether there are any economic benefits of sending the AoB and deeper connection-based price signal to connecting generators:

- We have downloaded the "Interactive Electricity Generation Cost Model – 2015"[42] ("Generation LRMC model") from the Ministry of Business, Innovation & Employment website[43];
- We removed Otahuhu (400MW) from the future list of candidate plants that the model could pick from, on advice from the Electricity Authority;
- Assigned each candidate generation project to the relevant transmission region (LNI, LSI, UNI and USI);
- Ran the Generation LRMC model to determine the new generation that is required to meet the underlying demand growth under the base case (ie, with no change to the way transmission services are priced, and a significant amount of spare capacity in the existing generation fleet in the scenario that assumes that the Huntly Rankine generation facilities are retained);
- Applied estimates of Transpower's generation driven capital expenditure program (as opposed to load) and the underlying growth in customer demand supplied by the Electricity Authority, which we used to estimate the LRMC of providing transmission services (in $/MWh) to generation facilities in each of the four regions. We then added this LRMC for transmission service onto the costs of each candidate plant, with the former differentiated based on which of the four regions that plant would be located in if built.
- Re-ran the "Interactive Electricity Generation Cost Model – 2015" based on the above information, to determine what new generation would now be built to meet the underlying demand growth (which, again, was provided by the Electricity Authority), after allowing for the transmission LRMC; and
- Estimated the change in the economic cost (inclusive of the transmission LRMC) between the original generation supply curve and the "re-ordered" supply curve to determine the economic benefits stemming from sending a price signal regarding transmission costs, to generators. We did this by estimating the overall costs (ie, upfront capital costs, fixed operating costs per MW, variable operating costs per MWh, and transmission costs per MWh) under both the base case and the "re-ordered" case.

42 http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/interactive-electricity-generation-cost-model

43 This model selects the lowest cost projects to meet demand growth but it is our understanding that it may not represent a complete list of all possible future generation options

We applied this procedure for a number of scenarios reflecting the amount of transmission capex and whether existing plants at Huntly are retained or not. The figures reported in the body of this report reflect the probability weighted (expected) outcome of two scenarios – with the primary difference between those two scenarios being whether existing plants at Huntly are retained (and therefore there is existing spare capacity in the generation fleet) or not. The remaining, low investment, scenario is reported in the sensitivity analysis described in latter sections of this report.

This analysis leads to the following key changes in the order of investment:

Table 5 Old vs. new - project schedule - assuming Huntly is retained

Old supply curve	Old project schedule		Re-ordered project schedule		Changes in supply curve
Project no. by year	Region	Project	Region	Project	Project no. by year
1 - yr.5	LNI	Tauhara_stage_2	LNI	Tauhara_stage_2	1 - yr.5
2 - yr.7	LSI	Hawea_Control_Gate_retrof it	n/a	Not required	n/a
3 - yr. 7	LNI	Hauauru_ma_raki_stage1	LNI	Hauauru_ma_raki_stage1	2 - yr.7
4 - yr.10	LNI	Hauauru_ma_raki_stage2	UNI	Hauauru_ma_raki_stage2	3 - yr 10
5 - yr.14	LSI	Lake_Pukaki	n/a	Not required	n/a
6 - yr 14	UNI	Rodney_CCGT_stage_1	UNI	Rodney_CCGT_stage_1	4 - yr 14
7 - yr 17	UNI	Rodney_CCGT_stage_2	UNI	Rodney_CCGT_stage_2	5 - yr 17

Table 6 Old vs. new - project schedule - assuming Huntly is not retained

Old supply curve	Old project schedule		Re-ordered project schedule		Changes in supply curve
Project no. by year	Region	Project	Region	Project	Project no. by year
1 - yr.2	LNI	Tauhara_stage_2	LNI	Tauhara_stage_2	1 - yr.2
2 - yr.3	LSI	Hawea_Control_Gate_Retr ofit	USI	Hawea_Control_Gate_R etrofit	8 - yr.18
3 - yr. 3	LNI	Hauauru_ma_raki_stage1	LNI	Hauauru_ma_raki_stage 1	5 - yr.9
4 - yr.6	LNI	Hauauru_ma_raki_stage2	LNI	Hauauru_ma_raki_stage 2	6 - yr.12
5 - yr.9	USI	Lake_Pukaki	USI	Lake_Pukaki	2 - yr 3
6 - yr 9	USI	Rodney_CCGT_stage_1	USI	Rodney_CCGT_stage_1	3 - yr.3

7 - yr 12	USI	Rodney_CCGT_stage_2	USI	Rodney_CCGT_stage_2	4 - yr 6
8 - yr 16	LNI	Turitea	LNI	Turitea	9 - yr 18
9 - yr 18	USI	PropopsedCCGT1	USI	PropopsedCCGT1	7 - yr 15

The above methodology is based on the following key assumptions:

- The transmission LRMC's underpinning this calculation have been predominately based on information provided by the Authority – in particular, the additional capex requirements required to service growth in generation output across four regions. These figures are not able to reflect the dynamic, real world effects on transmission investment stemming from the impact of locating generation in certain regions in response to the transmission price signal, and
- While the AoB and deeper connection-based charge are assumed, for the purpose of this analysis, to have the same potential coverage, the HHI threshold for application of the deeper connection will mean it applies to fewer assets. As a result, the deeper connection-based charge will in practice have a more limited coverage and therefore be less effective.

Finally, it is important to note that notwithstanding the extended coverage of the AoB charge as compared to the deeper connection-based charge, and the inherent uncertainty in this type of analysis, sending any, more cost-reflective, price signal will almost certainly not, in and of itself, lead to a diminishment in economic efficiency. Therefore, the lower bound economic benefit for this component of the CBA should be considered to be zero. Even, under this worst case scenario, the CBA is still net positive.

8.4. Pricing of historical investments in the network

8.4.1. Background

As discussed, the way in which historical investments in the network are priced will affect economic efficiency if it:

- Distorts future usage or investment decisions (eg, consumption or investment decisions); and
- Leads customers to make inefficient connection, disconnection or other investment decisions.

As outlined earlier, we consider the current arrangements may distort future consumption and investment decisions. We have modelled three different effects in this CBA. These are the impact:

- The RCPD charge has on future investment decisions by distribution businesses and other parties (eg, distributed generators);
- That current charges (in combination with the PDP arrangements) might have on the probability of some customers inefficiently exiting the grid; and
- That the HVDC charge might have on future generation investment decisions.

8.4.2. Methodology used to model benefits

More efficient investment decisions by distribution businesses or other parties, in response to the removal of the RCPD charge

OGW has utilised the following methodology to assess whether there are any economic benefits from removing the RCPD charge used to recover the costs of Transpower's historical investments that are not otherwise recovered through the AoB charge or the deeper connection-based charge, and instead, recovering residual transmission costs via a capacity charge on load customers. In particular, OGW has[44]:

- Obtained estimates of the RCPD charge (after allowing for the impact of the changes that will come into effect from 1 April 2017[45]) – this figure is approximately $2,300/MWh, based on previous information reported by Transpower[46];
- Compared this to the economic cost ($/MWh) of:
  - Constructing, and operating *new* distributed generation facilities – We have used the figures outlined in an earlier section of this report for the cost of diesel reciprocating facilities (as this was the most economical solution), converted these figures to $/MWh figures and then adjusted these for the fact that (a) users cannot predict the top 100 peak periods accurately in advance and are likely to achieve a 'success rate' of less than 100% and that (b) there is likely to be a cap on the cost effective use of distributed generation facilities as the shape of the load duration curve flattens in response to increased penetration of distributed generation[47] and that (c) it will take time for that cap to be reached. We have assumed that new distributed generators would have to operate for 200 half hourly periods for the purposes of our analysis, that they can only contribute new capacity up to 5% of system peak demand in any year, but that it will take 20 years to reach that level. A large proportion of the benefits from altering the RCPD charge come from avoiding losses associated with these types of future investments;
  - Operating *existing* distributed generation – We have reviewed information related to the type of existing generators that are currently connected to distribution networks in NZ[48], and have concluded that the short run marginal cost of operating each of these generators is likely to be less than the marginal RCPD price signal (even

44 It should be noted that the calculation of the benefits of removing the RCPD charge are premised on distribution businesses passing through (and being able to pass through) the RCPD price signal to DR and DG providers under the base case and that this would occur irrespective of any other change to arrangements related to the payment of distributed generators.

45 For example, 100 trading periods will be the basis for the charge starting 1 April 2017.

46 https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPM-Attachment-B%20background-supporting-analysis.pdf

47 As more distributed generators (and demand response) operate during peak periods, the load duration curve will, everything else being equal, flatten out, thus making it less economic for future distributed generators (and providers of demand response) to enter into the market, as they would likely have to operate over more hours in the year to ensure they operate during the 100 pricing periods.

48 Electricity Authority, "*Review of distributed generation pricing principles*," Consultation Paper, Unpublished, page 21

after April 2017). Therefore, it is assumed that all of these distributed generators would still be incentivised to operate into the future under the estimated RCPD charge. The economic cost of this has been estimated, based on the most up-to-date figure for Avoidable Cost of Transmission ('ACOT') payments ($62 million)[49], multiplied by 0.5 on the assumption that the production function is linear and therefore the actual costs of production would be half of the ACOT costs[50]. This equates to an annualised cost of capacity support of around $32,000 per MW; and

- Implementing new demand response programs – We have used the figures outlined in an earlier section of this report for the cost of demand response, converted these figures to MWh and then adjusted these to account for the fact that (a) users cannot predict the top 100 peak periods accurately in advance and are likely to achieve a 'success rate' of less than 100% and that (b) there is likely to be a cap on the cost effective use of demand response in response to the RCPD price signal as the shape of the load duration curve changes over time and that (c) it will take time for that cap to be reached. We have assumed 200 periods for the purposes of our analysis, that this would be capped at 5% of overall demand in any year for the same reasons as outlined above for distributed generation, and that it will take 20 years to reach that level.

- Offset the above costs by an estimate of the benefits of those investments, with this based on the LRMC of transmission investment[51] on average across Transpower's network ($34,611/MW for the base case) multiplied by the capacity support (MW) provided by the above three components in each year[52]. In making this assumption, we are implicitly assuming that the actual peak period will fall within one of the 100 pricing periods; and

49 Ibid

50 To be clear, this assumption is, if anything, likely to be conservative, as a large proportion of the existing fleet of distributed generators are renewables (over 60% are from hydro, wind and geothermal), and hence the production function may be more characterised by a relatively larger number of low cost generators, followed by a smaller number of higher cost generators.

51 To be clear, we have not included any benefits/costs to other parts of the value chain. For example, we have not included the benefit stemming from reduced wholesale costs of producing the energy that has been displaced.

52 So for example, for existing generation, this means that it is actually contributing slightly positive economic benefits in the future even with the RCPD charge, as the assumed LRMC ($34,611/MW) is greater than the assumed cost of generation ($32,000). This is obviously more than offset by our assumption that the RCPD charge will incentivise future distributed generation that is more expensive than the transmission alternative.

- Assumed that under both options, Transpower would generate less revenue from the residual charge relative to the current arrangements – with this obviously being more skewed towards the AoB charge than the deeper connection-based charge. However, more importantly, the underlying charge would be based on a measure of physical capacity under both arrangements[53]. This has led us to assume that there would be no material inefficient transmission price signal at all under either pricing option, as the responses to the RCPD charge discussed above[54] would not be materially incentivised under a charge that is lower (and much lower in the case of the AoB charge) and based on a measure of physical capacity thus, investment (and operation of distributed generation/demand response) occurring under the base case would cease under both options.

On a related issue, it is noted that the above analysis does not explicitly take account of the fact that under the deeper connection-based charge option, Transpower would be required to determine the application of the deeper connection charge annually**, based on a 5-year rolling average of flows.** This would smooth out variations between periods, and allow for a gradual change in the charge in response to the changing use of the grid, limiting the volatility of the charge.

53 It is our understanding that the Authority is proposing the residual charge be allocated to load based on each customer's physical capacity, and that physical capacity would be determined on the basis of one of the following: (a) transformer capacity; (b) line capacity; or (c) anytime maximum demand (AMD). Whilst the latter is not a physical measure per se, and in theory, could affect customer's marginal consumption and investment decisions, it is our understanding that the AMD would be determined as the average maximum demand in each of the 5 years leading up to the date of release of this draft second issues paper, and it would only be updated with a 10-year lag. Both factors are likely to mitigate the risk that the use of AMD could affect customer's marginal consumption and investment decisions. For new customers, it is our understanding that the Authority is proposing that Transpower develop methodologies for dealing with the entry of new load customers, with the aim that they face residual charges similar to comparable load customers. This basis of charging would appear to us to not comprise economic efficiency – because the of the decoupling of the charge from the customer marginal investment and consumption decisions.

54 The estimated gross benefit from more efficient pricing of historical investment comes entirely from transmission being more efficient than other new investments such as diesel generation. However, it should be noted that the modelling of this benefit (from more efficient pricing) in isolation implicitly assumes that existing distributed generators might cease operations straight away in response to the effective removal of the RCPD price signal. This is a conservative assumption, as this: a) actually leads to a reduction in the benefit of removing the RCPD charge (because the cost of existing distributed generation is assumed to be less than the LRMC), and b) does not reflect the fact that many of these existing plants will continue to operate in response to the new cost-reflective transmission charge (e.g., the AoB charge). To be conservative, we have not explicitly modelled this in the "Future investment in services or equipment that may otherwise be substitutes for transmission services" section – but this the likely outcome.

In practice, what this means is that in addition to the removal of the RCPD charge that has been discussed above, a new "effective" per MWh charge will be created for those customers allocated costs under the deeper connection-based charge. It is effective, because the way it works is that the costs that are recovered via the deeper connection-based charge *(after they have been spent)* will be based on a customer's rolling 5-year average of consumption - hence the lower a customer's 5-year rolling average is, the lower their allocation of the deeper connection-based charge will be (hence creating an effective price signal based on MWh).

In theory, this results in end-customers of Transpower being faced with a marginal price signal that is designed to recover a historical investment. Put simply, users can in theory manipulate the charges they face by manipulating their use, with no corresponding reduction in Transpower's future costs. For example:

- Generators will in effect face a capacity tax on the power they generate, since their deeper connection-based charge is based on their actual power output;
- Direct connect customers will be faced with a higher marginal price signal than would otherwise be efficient, hence in theory they will consume less than efficient levels of electricity, and
- End-customers of distribution businesses will be faced with higher variable retail charges than would have otherwise been efficient, hence in theory they too will consume less than efficient levels of electricity.

In considering the economic implications of this, we have had regard to the:

- 5-year rolling average aspect of the charge – this aspect of the charge means that for a user to *materially* benefit from a change in usage, they must not just "manipulate" their usage in a single year, but continue to do so for multiple years. This effectively reduces the marginal price signal to 20% of its annual figure. This also reduces the likelihood that end-customers of distribution businesses would see a variable price signal that reflects these costs (rather, this would more likely be recovered through a fixed charge), which, if this were the case, means those customers would not reduce their levels of consumption below otherwise efficient levels (e.g., via demand response; installation of PV systems; energy efficiency);
- Likelihood that most generators are likely to be subjected to a deeper connection-based charge due to the relatively high concentration of flows in assets that serve them directly or indirectly[55] – this reduces the risk that the market for generation services, including the bidding behaviours of existing generators and location of new generators, is materially skewed away from otherwise efficient levels. That said, in our opinion, this does not negate the risk entirely and
- The inelastic nature of electricity consumption by existing customers – the economic impact of the price signal for load customers relates to their elasticity of demand, which, as alluded to, is inelastic. Everything else being equal, this mutes the economic loss stemming from pricing above marginal cost for consumption.

55 That is not to say all assets serving generators will be subject to the deeper connection-based charge, as obviously, some assets deep in the grid may not be covered.

For the above reasons, we have not quantified this loss in economic efficiency in the base case, although we believe that from an economic perspective, it is definitely a disadvantage of the deeper connection-based charge relative to the AoB charge.

A lower probability of some customers exiting the grid inefficiently

As noted, the current charging regime may lead a customer to inefficiently disconnect from the network if:

- Their current transmission charges are above their willingness to pay; *yet*
- The costs that Transpower would avoid if they ceased to take electricity via that transmission connection were less than their willingness to pay.

To support the assessment of the latter issue, OGW has utilised the following generic methodology to assess whether there are any economic benefits from adopting a more comprehensive PDP. In particular, OGW has:

- Analysed information provided by the Authority in respect of the potential for some large customers to exit from the grid due to transmission prices that:
  - exceed their willingness to pay for transmission services; but which
  - are greater than the incremental cost of supplying them with transmission services.
- Estimated the current gross profit[56] of those parties, assuming that the current transmission pricing arrangements continue;
- Estimated the probability that those parties would face negative gross profits over the remaining life of their facilities, under:
  - existing transmission prices; and
  - revised transmission prices under the PDP, with this based on an estimate of the incremental cost of supply[57];
- Identified whether the transmission prices under the more comprehensive PDP lead the estimated negative gross profits for the facility to become positive gross profits (thus implying that the PDP is explicitly ensuring that a facility will continue to operate due to the now positive gross profits that it would not have been achieving had the more comprehensive PDP not been in place)[58]; and

56 This is assumed to reflect the producer surplus generated from the on-going operation of the business. This was based on historical, publically available financial information.

57 To estimate this, we have assumed that the avoidable cost of supply is $0.005/kWh multiplied by that customer's existing consumption. This is based on our estimate of the marginal operating and maintenance costs of an electricity transmission network.

58 We note that if a facility still has a negative gross profit after the revised PDP is implemented, that does not guarantee that it will discontinue its operations. However, for the purposes of our analysis, a negative gross profit would provide no producer surplus and therefore no economic benefit.

- Estimated the likelihood of the annual change in gross profit, as a proxy for producer surplus, between the two scenarios (by multiplying an estimate of the probability of the scenario occurring[59] with the quantum of the 'new' positive gross profit), and applied it over the estimated remaining life of the facility[60].

The benefits are assumed to be the same for both the AoB charge and the deeper connection-based charge.

More efficient future investment in generation related assets

Conceptually, the HVDC charge that will operate from 1 April 2017 onwards (the SIMI) will, everything else being equal, lead new generators to favour locating in the North Island over the South Island, so as to avoid the HVDC SIMI charge. However, to our mind, the HVDC SIMI charge is unlikely to reflect the marginal cost of transmitting an additional MWh through the HVDC interconnector (quite simply, because it is designed to recover the average cost of the connection, which is almost certainly likely to be higher than the marginal cost), thus any change in the location of new generation promoted by the HVDC SIMI charge is likely to lead to inefficient sources of generation being constructed in the future.

To model this, we used a similar approach to how we modelled the impact that the AoB and deeper connection-based charge would have on the location of future generation investment. In particular:

- We again used the "Interactive Electricity Generation Cost Model – 2015" ("Generation LRMC model") from the Ministry of Business, Innovation & Employment website[61], and made the same adjustments as outlined in Section 8.3.2;
- We sourced an estimate of the $/MWh impact of the HVDC SIMI charge from previous work Scienta consulting[62] has undertaken on this issue and then ran the Generation LRMC model:
  - Assuming the HVDC SIMI was applied to South Island Generators; and
  - Assuming the HVDC SIMI was not applied to South Island Generators.
- We determined the NPV of the difference in the cost of generation schedules (not inclusive of the cost of the HVDC SIMI) between the two runs based on the merit order of the supply of projects. This cost included the upfront capital costs, fixed operating costs per MW and variable operating costs per MWh.

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59 This was based on an assessment of the underlying prices for the goods sold by the customer/s, the relationship between those commodity prices and the customer/s gross profit, and a high level estimate of the distribution of the underlying commodity price over the remaining life of the facility.

60 The implicit assumption is that the costs that Transpower doesn't recover from these customers now (because of the use of the PDP), will now be recovered from its remaining customer base in a manner that does not distort the consumption or investment behaviour of those customers (thus it does not lead to a consequential loss in economic efficiency).

61 http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/interactive-electricity-generation-cost-model

62 https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Scientia-Consulting-HVDC-report.pdf, slide 10

The outcomes showed a shift of projects that would have been built in the South Island towards projects in the North Island, simply because of the effect of the HVDC SIMI. In particular, the following projects changed – see Table 7. The benefits are assumed to be the same for both the AoB charge and the deeper connection-based charge.

Table 7 Old vs. Re-ordered project schedule

Old supply curve	Old project schedule		Re-ordered project schedule		Changes in supply curve
Project no. by year	Node	Project	Node[63]	Project	Project no. by year
1 - yr.4	C	Tauhara_stage_2	C	Tauhara_stage_2	1 - yr.4
2 - yr.5	E	Hawea_Control_Gate_Retrofit	E	Hawea_Control_Gate_Retrofit	2 - yr.5
3 - yr. 7	E	Hauauru_ma_raki_stage1	C	Turitea	3 - yr.6
4 - yr.10	E	Hauauru_ma_raki_stage2	C	Proposed CCGT1	4 - yr.8
5 - yr.11	E	Lake_Pukaki	E	Hauauru_ma_raki_stage1	5 - yr.11
6 - yr.13	E	Rodney_CCGT_stage_1	E	Hauauru_ma_raki_stage2	6 - yr.15
7 - yr.16	E	Rodney_CCGT_stage_2	C	Tikitere_LakeRotoiti	7 - yr.16
8 - yr.19	C	Turitea	E	Lake Pukaki	8 - yr. 16
			E	Rodney_CCGT_stage_1	9 - yr. 19

8.5. More efficient *quantity* of transmission and generation services being demanded by the market

8.5.1. Background

As noted, the cost of providing transmission services to load customers is inextricably linked to the level of peak demand that end customers place on the network.

The quantum of peak demand may in theory be affected by the variable retail price that end customers pay for electricity services. In particular, everything else being equal, the higher the variable retail price, the lower the amount of energy that will be consumed by end customers, which in turn has a consequential impact on peak demand, and therefore, transmission capacity requirements.

63 Node C represents projects on the North Island, while node E represent projects on the South Island

In this context, it is possible that either of the main two transmission pricing options may change the variable retail price that end customers face (relative to the base case), and therefore the quantity of energy that they consume at times of system peak demand. This in turn would lead to lower overall costs of supply[64].

8.5.2. Methodology used to model benefits

In measuring the incremental benefits of the options within the CBA Model, OGW has made the assumption that under the new TPM (but not the existing one), distribution businesses will be incentivised to charge customers a variabilised electricity price to encourage them to reduce the quantity of electricity they consume, and so defer charges for increased transmission capacity until they are prepared to pay for it. To do this, OGW first calculated the likely impact of the Base Case to then understand the incremental impact for each of the options. The following outlines our methodologies for these two steps.

Calculating the Base Case impact

The Base Case scenario effectively forecasts what the impact of the forecast demand-driven capital expenditure is on the current charging regime (ie, the Interconnection Charge).

To do this, we have simply made the assumption that changes in future demand-driven transmission charges would not be recovered through higher variable retail charges, due to the fact that the current transmission pricing arrangements do not provide an opportunity for customers' future consumption behaviour to affect transmission bills (ie, there is no forward-looking price signal for demand-driven capital expenditure). Instead, it is assumed that these would be recovered through fixed charges.

Measuring the impact on load customers' demand and the consequential economic benefits under the revised transmission pricing arrangements

The methodology used to measure the benefits under the two approaches is the same, however, we use different assumptions about the coverage of the two options for pricing:

- Using information provided by the Authority, we determined the annual cost of demand-driven capital expenditure related to load customers in each region;
- An adjustment factor was applied to the annual capital expenditure to reflect the different coverages under each of the two options (the same adjustment is applied to the calculation of the relevant base case)[65];

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64 To be clear, as quantity changes in response to the new price signal, there will also be consequential changes in the level of consumer and producer surplus. For example, if the change in price meant that demand reduced by 10MW, then that is 10MW that end customers no longer consume, and hence, they will no longer accrue the difference between the marginal benefit that they would have otherwise generated from consuming that additional unit of energy and the marginal price they would have incurred in purchasing that additional unit of energy. For the purposes of this CBA, we have ignored this, as we are of the view that this will be immaterial in the context of this analysis. In part, this stems from the significant differential between the marginal energy (kWH) price that customers face, and which underpins their loss in consumer surplus, as compared the actual marginal cost of providing that energy during those peak periods.

65 This is discussed in more detail in the next section of the report.

- Calculate an equivalent revenue requirement for the forecast expenditure for each region using the capital recovery and maintenance ratios provided by the Authority;
- Convert the revenue requirement to a percentage increase in overall transmission charges for each region;
- Convert the percentage change in the overall transmission charges for each region into a percentage change in the volumetric retail component (based on customer information from the Commerce Commission and an assumption regarding the average volumetric component);
- This percentage change in the volumetric retail component for each region was then compared to the percentage change for each region under the relevant base case (zero), and this increase was assumed to flow through to variable retail charges, and consequently, volumes were adjusted down by applying an estimate of the price elasticity of demand of -0.4[66] in conjunction with that percentage difference;
- The percentage reduction in energy is then converted into a kW unit of measure for each region; and
- The reduction in kW's is then multiplied by the estimated:
  - Load-driven LRMC for transmission services each region in each year, and
  - Generation-driven LRMC for transmission services for each region.

66 More information on the basis for this estimate can be found in Appendix D.

9. Summary of models used and key assumptions

9.1. Overview of model

OGW has relied on 3 models to support this CBA. These are:

- The CBA model;
- An LRMC model for transmission services; and
- A LRMC model for NZ electricity generation, which leverages off the "Interactive Electricity Generation Cost Model" published by Ministry of Business, Innovation & Employment in NZ.

The CBA model is described in more detail below. The key assumptions underpinning that model are outlined in Appendix D. The LRMC model is discussed in Appendix A. The NZ electricity generation LRMC model has been discussed in Section 8.3 of this report, and therefore, will not be repeated.

9.2. Overview of CBA model

The CBA Model compares the net present value (NPV) of the costs and benefits of the different options relative to the base case. The model incorporates the outputs of the other models and other inputs (such as the proportion of the Interconnection Charge for each customer and the transmission proportion of their retail charges) to determine the costs and benefits.

The CBA Model uses an incremental approach to comparing the options with the base case. This means that costs and/or benefits that would have arisen through the base case scenario have been "netted-off" from the costs and benefits of the two options. In relation to the calculation of the benefits, the model does this through modelling the expected outcome of the base case in order to determine the incremental benefits of the two options in comparison to the base case outcomes. From the cost perspective (which is discussed further below), we have focused on what additional costs would be required beyond those that would be incurred under the base case.

An NPV analysis of the incremental costs and benefits is then undertaken to provide an accurate comparison of the options and to remove any timing differences between the costs and benefits. Sensitivity testing regarding discount rates, term of analysis and forecasts has been incorporated into the CBA Model in order to provide a more complete picture of the different options and what is driving the outcome of the calculations.

9.3. Benefits

The following table summarises the value we have ascribed to each of the benefits that we discussed in Section 8 of this report, for the AoB option.

Table 8: Summary of benefits for the AoB charge compared to the base case

Type of benefit	Value (NPV)
More efficient future investment in services that may otherwise be substitutes for transmission services	
▪ Alternatives to transmission investment (section 8.2.2, part 1)	$1,202,796
▪ Deferrals to transmission investment (section 8.2.2, part 2)	$3,010,839
More efficient co-investment in generation and transmission services (section 8.3)[67]	$92,748,124
More efficient quantities of services being demanded (section 8.5)	$313,601
Benefit from more efficient pricing of historical investments	
▪ Removing the SIMI charge (section 8.4.2, part 3)[68]	$13,731,094
▪ Replacement of the RCPD charge with a charge based on physical capacity (section 8.4.2, part 1)	$89,974,887
▪ Introducing a more comprehensive PDP (section 8.4.2, part 2)	$10,302,309
TOTAL BENEFITS	**$211,283,650**

Source: OGW

Table 9 summarises the value we have ascribed to each of the benefits that we discussed in Section 8 of this report, for the deeper connection option.

Table 9: Summary of benefits for the deeper connection charge compared to the base case

Type of benefit	Value (NPV)
More efficient future investment in services that may otherwise be substitutes for transmission services	
▪ Alternatives to transmission investment	$601,398
▪ Deferrals to transmission investment	$0
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$143,389

67 This includes the benefit of sending a more cost reflective transmission price to prospective electricity generators. This represents the average of the two cases – with Huntly being retained ($55m), and without Huntly being retained ($130m).

68 This analysis reflects a 30-year timeframe, as the 20-year timeframe was unduly influenced by specific timing related issues that affected when generation assets were expected to be developed in the model, which skewed the results when undertaken over this shorter evaluation period.

Benefit from more efficient pricing of historical investments	
Removing the SIMI charge	$13,731,094
Replacement of the RCPD charge with a charge based on physical capacity	$89,974,887
Introducing a more comprehensive PDP	$10,302,309
TOTAL BENEFITS	**$207,501,201**

Source: OGW

The overarching methodology used to develop these benefits was discussed in the previous section of this report.

To differentiate between the AoB option and the deeper connection option, we have assumed that:

- 100% of the value of demand-driven related capital expenditure would be signalled to load customers via the AoB charge (because all new investments would be covered by the charge; whilst
- 50% of the value of demand-driven related capital expenditure would be signalled to load customers via the deeper connection charge.

The latter is based on the assumption that recovery through the AoB charge is likely to be greater than the deeper connection charge since it does not incorporate the graduated cut-off of HHI=2000-7000 of the deeper connection charge, which means for example, very deep grid investments – which are likely to be very costly – would not be covered by the deeper connection-based charge. Furthermore, there is risk that even within these HHI bounds, users may not believe that their behaviour will alter the timing of the new asset investment, due to the indivisibility of the asset (ie, there are multiple users of the asset, and any response they make may not change the size or timing of the investment). Furthermore, information provided by the Authority indicated that if the deeper connection-based charge was applied to historical investments, it would have been levied on around 50% of those investments. This provides a reasonable indication for the deeper connection charge going forward since the coverage is determined by the HHI of flows rather than other factors such as asset size, value etc.

9.4. Incremental and avoided costs

Given the incremental focus of the analysis, the consideration of the costs for each of the options is based on:

- the **incremental costs** that will be incurred by the industry under the different options compared to the status quo; and also
- any **avoided incremental costs** as a result of the implementation of the options.

These are discussed in more detail below.

9.4.1. Incremental costs

In considering the incremental costs for each option we have separated the analysis into two segments:

- Up-front costs; and
- Ongoing costs.

The following provides a summary of the approach that we have used for each of these segments.

Up-front costs for options

Transpower is the most likely industry participant that will experience an increase in up-front costs with either option compared to the status quo. This is because Transpower will have to develop internal policies and procedures to ensure that the new pricing approach becomes part of its 'business-as-usual' practices. The cost associated with these policies and procedures would not be incurred if an alternative pricing approach were not adopted.

The forecast costs associated with the implementation of a new pricing methodology is unavoidably subjective, we have therefore incorporated a sensitivity test regarding our cost assumptions in section 10.7.

In addition to the internal resource costs, there is likely to be external assistance required with reviewing systems and processes in preparation for the new charging approach. For the purposes of the analysis we have estimated this to be $1.27 million for the deeper connection option and $1.52 million for the AoB option (due to the higher granularity required).

It is expected that the Electricity Authority will also incur additional up-front costs with establishing policies and guidelines for the two different options (in excess of the status quo resourcing requirements). These incremental costs will be both internal costs (Full Time Equivalent staff - FTEs) and external assistance (assumed to be $500,000).

Of the other industry participants – Load Customers and Generators – it is not expected that there will be any *material* incremental up-front costs as a result of the different options being considered. This is not to say that some industry participants will not have to spend some time familiarising themselves with a new TPM, however we have assumed that this would not be material.

Ongoing costs for options

Load Customers, Generators and the Authority are expected to incur ongoing administration costs in relation to transmission pricing under the different options. However, these costs are unlikely to be materially different to the costs that will be incurred by these participants under the base case and therefore no incremental costs have been attributed on an ongoing basis.

When considering the impacts on Transpower specifically, Transpower will require resources to manage pricing under both of the two pricing options, however, it is expected that there will be greater additional costs associated with the AoB charge as it is expected to be applied at a more granular level than the deeper connection-based charge.

Summary of incremental costs for the different options

Based on the above discussion on the incremental costs for the different pricing approaches, Table 10 provides a summary of the incremental costs for each stakeholder under the two options.

Table 10: Summary of incremental costs incorporated in analysis[69]

Option	Cost Category	Stakeholder	Incremental Cost Values
Deeper Connection	Up-front costs	Transpower	$1,270,675
		Load Customers	$0
		Generators	$0
		Electricity Authority	$770,675
	Ongoing costs	Transpower	$60,150 (p.a.)
		Load Customers	$0
		Generators	$0
		Electricity Authority	$0
Area of Benefit	Up-front costs	Transpower	$1,520,675
		Load Customers	$0
		Generators	$0
		Electricity Authority	$770,675
	Ongoing costs	Transpower	$120,300 (p.a.)
		Load Customers	$0
		Generators	$0
		Electricity Authority	$0

This results in a present value (using the default discount rate of 8 per cent and 20 years) for the costing analysis of:

- Deeper Connection: $2,631,912
- Area of Benefit: $3,472,473

69 In calculating these costs, we have used an annual FTE cost of $120,300 which is based on Strata Energy Consulting's Draft Decision for its review of Transpower's expenditure - http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-individual-price-quality-regulation/transpowers-price-quality-path-from-2015-to-2020

9.4.2. Avoided incremental costs

In addition to the incremental costs associated with implementing either of the proposed options, there is also likely to be some avoidance of future costs through implementing either option. Under the status quo there is considerable, ongoing debate regarding the TPM and its structure. By adopting a new approach that is well documented and understood, it would be expected that some costs associated with disputes and reviews of the TPM could be avoided in the future.

We do not envisage that the adoption of either the deeper connection-based or AoB options will avoid all costs associated with disputes regarding the TPM, but they should assist in reducing these costs. We expect that the impact of this is likely to be different between the two options. This is due to the fact that they require different assumptions and are applied differently:

- The deeper connection-based charge is based on the flow tracing and the use of the HHI index, however it is estimated to cover only 50 per cent of investments; whereas
- The AoB will involve specification of detailed areas of benefit for customer identification and is estimated to cover 100 per cent of investments.

To measure the impact of the avoided incremental costs, we have developed a base case of the dispute-related costs under the status quo and applied a reduction based on the estimated impact that the option may have on the different cost elements. It is difficult to know the level of disputes under the status quo as the majority of the dispute-related costs over the last few years appear to have been driven by the review of the TPM itself. We have therefore sought to separate different elements so as to provide a more granular approach to the analysis.

We have separated the potential for avoided costs into:

- Annual dispute-related costs for the Electricity Authority;
- Annual dispute-related costs (exc. the Electricity Authority); and
- Periodic dispute-related costs (including use of external resources).

The annual dispute-related costs relate to the estimated FTE costs incurred by each of the participants in relation to pricing disputes under the status quo. As with the incremental cost analysis, we have used an annual FTE cost of $120,300. For the Electricity Authority, we have assumed that there would be 2 FTEs that would be focused on disputes for 75% of their time. While for other participants, it is expected that only 25% of one FTEs time would be required for each participant.

To estimate the likely periodic costs associated with disputes, we have relied on the Electricity Authority's estimate of $4.5 million every five years for the industry (including external resources).[70] This cost appears reasonable given the number of participants involved.

70 Electricity Authority, *Transmission Pricing Methodology: Issues and Proposal - Consultation Paper*, October 2012, p. F15.

Proportion of costs avoided

In considering the potential for avoided dispute-related costs, we note that there has been considerable divergence between industry participants on the quantum of such a benefit.[71] Given the subjective nature of this potential benefit, we have erred on the conservative side when developing our estimates, however we note that in section 10.7 we consider the sensitivity of the analysis to different cost assumptions.

We consider it likely that industry participants (other than the Electricity Authority) would be able to save part of an FTE as a result of the adoption of one of the proposed pricing options. It is more likely that staff will be able to divert time that would have otherwise been occupied with TPM disputes to other matters within the business. This is a benefit to the industry participant that would not occur under the status quo. In estimating these opportunity cost savings associated with avoiding TPM dispute-related costs, we have relied on, similar to the estimated periodic TPM dispute-related costs outlined below, our estimates regarding the coverage and granularity of the options.

In our view, the Electricity Authority has scope to avoid future overhead costs through a new TPM because a more stable and cost-reflective TPM will result in fewer regulatory reviews and responses required to industry submissions regarding the TPM.

Our other focus has been on the likelihood of the proposed options reducing the periodic dispute-related costs. We consider that compared to the annual costs, these are more likely to be impacted by a new TPM and have greater potential for cost avoidance. There will still be dispute-related costs, however by 'locking-down' key aspects of the TPM, some of the costs can be avoided.

We have applied a differential between the two different options in their ability to avoid dispute-related costs based on the discussion earlier regarding the estimated coverage of the deeper connection option and the greater granularity of the AoB option. The more granular approach under the AoB option results in greater coverage of investments throughout the network and therefore fewer investments that are outside the transmission access charge. If the TPM is 'locked-down' following this review, it would be expected that the fewer investments that fall outside, the fewer the dispute-related costs between the EA and the industry.

Table 11 provides our assumed proportions for each element.

Table 11: Assumptions used for dispute-related cost avoidance

Avoided Cost Element	Deeper Connection	Area of Benefit
Proportion of avoided Electricity Authority annual costs	25%	30%
Proportion of avoided annual costs (exc. Authority)	20%	35%
Proportion of avoided periodic costs	20%	40%

71 When considering dispute-related costs, we are not confining this to the legal definition of disputes but rather such things as submissions, regulatory reviews, lobbying for methodology change, etc.,

The key understanding from this analysis is that we consider that the adoption of any new TPM approach will:

- Reduce the Electricity Authority's annual costs related to disputes;
- Reduce the internal resourcing requirements for industry participants (reflected in an opportunity cost saving); and
- Reduce the likelihood (and therefore costs) of periodic dispute-related costs.

This results in a present value (using the default discount rate of 8 per cent and 20 years) for cost avoidance of:

- Deeper Connection $3,036,974
- Area of Benefit $5,512,914

It is possible that there may be additional future benefits of cost avoidance through adjustments to the options to remove subjectivity, however, this needs to be weighed-up against the cost associated with removing this subjectivity.

9.4.3. Net cost impact

The net impact of the incremental and avoidable cost of the two options (based on 8 per cent discount rate and 20-year analysis) is:

- Deeper Connection $405,062
- Area of Benefit $2,040,441

This indicates that while the AoB option is expected to impose greater costs in its implementation and ongoing administration, it is anticipated that the avoided costs of the AoB will more than offset these additional costs when compared to the deeper connection option.

A consideration of the sensitivity of the outcome of the analysis to the cost assumptions is considered in section 10.7 of the sensitivity analysis section.

10. Model results and sensitivity analysis

This section highlights the:

- Results of our analysis;
- Sensitivity of the results to changes in the discount rate;
- Sensitivity of the results to changes in the cost of a given quantity of transmission investment constructed over the evaluation period;
- Sensitivity of the results to changes in the proportion of future transmission investment that can be offset by the adoption of more economic alternatives such as embedded diesel generation;
- Sensitivity of results if the price signal increases the scrutiny of transmission projects, leading Transpower to adopt more efficient transmission projects;
- Sensitivity of the results to changes in the length of the evaluation period; and
- Sensitivity of the results to changes in the cost assumptions.

10.1. Results of our analysis

Table 12 and Table 13 summarises the results of our analysis for the options.

Table 12: Summary of results for the AoB charge compared to the base case

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$4,213,635
More efficient co-investment in generation and transmission services[72]	$92,748,124
More efficient quantities of services being demanded	$313,601
Benefit from more efficient pricing of historical investments	$114,008,290
Net incremental and avoided costs	$2,040,441
NET BENEFIT (COST)	**$213,324,092**

Source: OGW

72 This represents the average of the two cases - with Huntly being retained ($55m), and without Huntly being retained ($130m).

Table 13: Summary of results for the deeper connection charge compared to the base case

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$601,398
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$143,389
Benefit from more efficient pricing of historical investments	$114,008,290
Net incremental and avoided costs	$405,062
NET BENEFIT (COST)	**$207,906,263**

Source: OGW

The following sections highlight the sensitivity to changes in selected key parameters.

10.2. Sensitivity of results to changes in the discount rate

The following tables summarise the results of our analysis.

Table 14: Summary of results for the AoB charge assuming a 6% discount rate

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$5,508,028
More efficient co-investment in generation and transmission services	$93,368,352
More efficient quantities of services being demanded	$400,240
Benefit from more efficient pricing of historical investments	$139,665,379
Net incremental and avoided costs	$2,769,208
NET BENEFIT (COST)	**$241,711,207**

Source: OGW

Table 15: Summary of results for the deeper connection charge assuming a 6% discount rate

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$703,188
More efficient co-investment in generation and transmission services	$93,368,352
More efficient quantities of services being demanded	$182,609
Benefit from more efficient pricing of historical investments	$139,665,379
Net incremental and avoided costs	$816,639
NET BENEFIT (COST)	**$234,736,168**

Source: OGW

Table 16: Summary of results for the AoB charge assuming a 10% discount rate

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$3,255,359
More efficient co-investment in generation and transmission services	$91,038,292
More efficient quantities of services being demanded	$248,826
Benefit from more efficient pricing of historical investments	$94,655,038
Net incremental and avoided costs	$1,464,856
NET BENEFIT (COST)	**$190,662,370**

Source: OGW

Table 17: Summary of results for the deeper connection charge assuming a 10% discount rate

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$521,307
More efficient co-investment in generation and transmission services	$91,038,292
More efficient quantities of services being demanded	$114,033
Benefit from more efficient pricing of historical investments	$94,655,038
Net incremental and avoided costs	$79,996
NET BENEFIT (COST)	**$186,408,664**

Source: OGW

10.3. Sensitivity of results to changes in the cost of a given quantity of transmission investment

Table 18 summarises the results of analysis based on a capital expenditure program that is half the Base Case capital expenditure program (this includes changes to the LRMC calculation). This assumes that the same level of future demand is met. In considering the impact of this lower capex program, we have decreased the size of the deferrals that could occur through the use of embedded generation to $20 million (as opposed to $40 million that is used base analysis[73]).

Table 18: Summary of results for the AoB charge assuming a lower cost capex program

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$8,182,254
More efficient co-investment in generation and transmission services	$41,418,253
More efficient quantities of services being demanded	$94,160
Benefit from more efficient pricing of historical investments	$249,994,594
Net incremental and avoided costs	$2,040,441
NET BENEFIT (COST)	**$301,729,701**

Source: OGW

73 See section 8.22 for a discussion of this in the context of the base analysis.

Table 19: Summary of results for the deeper connection-based charge assuming a lower cost capex program

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$1,651,585
More efficient co-investment in generation and transmission services	$41,418,253
More efficient quantities of services being demanded	$43,952
Benefit from more efficient pricing of historical investments	$249,994,594
Net incremental and avoided costs	$405,062
NET BENEFIT (COST)	**$293,513,446**

Source: OGW

10.4. Sensitivity of results to changes in the proportion of future demand-driven transmission investment that can be offset by diesel generation

The following table summarises the results of our sensitivity analysis.

Table 20: Summary of results for the AoB charge assuming a 50% increase in the proportion of future transmission investment that can be offset by diesel generation

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$8,230,195
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$313,601
Benefit from more efficient pricing of historical investments	$114,008,290
Net incremental and avoided costs	$2,040,441
NET BENEFIT (COST)	**$217,340,651**

Source: OGW

Table 21: Summary of results for the deeper connection charge assuming a 50% increase in the proportion of future transmission investment that can be offset by diesel generation

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$1,603,957
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$143,389
Benefit from more efficient pricing of historical investments	$114,008,290
Net incremental and avoided costs	$405,062
NET BENEFIT (COST)	**$208,908,822**

Source: OGW

Table 22: Summary of results for the AoB charge assuming a 50% reduction in the proportion of future transmission investment that can be offset by diesel generation

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$1,202,796
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$313,601
Benefit from more efficient pricing of historical investments	$114,008,290
Net incremental and avoided costs	$2,040,441
NET BENEFIT (COST)	**$210,313,253**

Source: OGW

Table 23: Summary of results for the deeper connection charge assuming a 50% reduction in the proportion of future transmission investment that can be offset by diesel generation

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$601,398
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$143,389
Benefit from more efficient pricing of historical investments	$114,008,290
Net incremental and avoided costs	$405,062
NET BENEFIT (COST)	**$207,906,263**

Source: OGW

10.5. Sensitivity of results if the price signal increases the scrutiny of transmission projects, leading Transpower to adopt more efficient transmission projects

The following table presents the results of the potential impact that the additional scrutiny that a more cost-reflective price may have on future transmission costs. Such projects could be in the form of replacement projects, demand-driven projects, or projects that lead to improvements in the level of service received by customers.

The results are based on the increased scrutiny leading to a:

- Deferral in the timing of a Transpower capital investment by 1 year; or
- Permanent cost reduction (through the identification of a more efficient solution).

For the purposes of this sensitivity analysis, OGW has assumed that these two components contribute equally to the outcome – ie, a 5% efficiency is comprised of 2.5% through the deferral in timing and 2.5% through a permanent reduction in costs.

As discussed, benefits of this type are available to the extent that existing procedures, processes and stakeholder scrutiny are not currently resulting in a comprehensive assessment of Transpower's investment proposals (including alternatives to those proposals).

For the purposes of this analysis, it is assumed that both transmission pricing options would deliver similar levels of scrutiny, therefore, we have not differentiated their impact.

Table 24: Summary of the impact that increased scrutiny might have on future transmission costs

Option	5% Efficiency	10% Efficiency
$1.5 billion Capital Program	$19,881,749	$39,763,497
$2 billion Capital Program	$26,508,998	$53,017,996
$2.5 billion Capital Program	$33,136,248	$66,272,495

Source: OGW

10.6. Sensitivity of results to changes in the length of the evaluation period

The following table summarises the results of our sensitivity analysis. It should be noted that generation and transmission investment were co-optimised over a 20-year period in all cases – that is, the 20-year generation and transmission investment results were used in both the 10-year and 30-year sensitivity analyses[74].

Table 25: Summary of results for the AoB charge assuming a 10-year evaluation period

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$1,683,190
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$101,654
Benefit from more efficient pricing of historical investments	$76,902,927
Net incremental and avoided costs	$669,155
NET BENEFIT (COST)	**$172,105,050**

Source: OGW

74 Our methodology optimises using full capital costs in the year of commissioning of the plant, as opposed to annualised values. Using this modelling approach, and a 10-year evaluation period, would produce distortions, as the benefits of using high upfront cost / low operating cost plant would not be adequately captured. Beyond 20 years it is assumed that differences would be minimal due to discounting factors.

Table 26: Summary of results for the deeper connection charge assuming a 10-year evaluation period

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$405,218
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$48,042
Benefit from more efficient pricing of historical investments	$76,902,927
Net incremental and avoided costs	($369,382)
NET BENEFIT (COST)	**$169,734,929**

Source: OGW

Table 27: Summary of results for the AoB charge assuming a 30-year evaluation period

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$5,001,852
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$512,808
Benefit from more efficient pricing of historical investments	$156,895,979
Net incremental and avoided costs	$2,675,612
NET BENEFIT (COST)	**$257,834,375**

Source: OGW

Table 28: Summary of results for the deeper connection charge assuming a 30-year evaluation period

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$700,863
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$234,437
Benefit from more efficient pricing of historical investments	$156,895,979
Net incremental and avoided costs	$763,780
NET BENEFIT (COST)	**$251,343,183**

Source: OGW

10.7. Sensitivity of results to changes in the implementation cost assumptions

The following table summarises the results of our sensitivity analysis. It can be seen from this that adjusting the estimated implementation costs can impact on the preferred option for the analysis.

Table 29: Summary of results for the AoB charge assuming a 100% increase in the estimated implementation costs

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$4,213,635
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$313,601
Benefit from more efficient pricing of historical investments	$114,008,290
Net incremental and avoided costs	($1,432,032)
NET BENEFIT (COST)	**$209,851,618**

Source: OGW

Table 30: Summary of results for the deeper connection charge assuming a 100% increase in the estimated implementation costs

Type of benefit	Value (NPV)
Future investment in services that may otherwise be substitutes for transmission services	$601,398
More efficient co-investment in generation and transmission services	$92,748,124
More efficient quantities of services being demanded	$143,389
Benefit from more efficient pricing of historical investments	$114,008,290
Net incremental and avoided costs	($2,226,849)
NET BENEFIT (COST)	**$205,274,352**

Source: OGW

11. Qualitative description of the impact that the transmission pricing options might have on other parts of the electricity value chain

The following sections provide a brief qualitative description of the impact that the transmission pricing options might have on other parts of the electricity value chain.

11.1. Distribution

It is feasible that changing the way transmission services are priced may also have flow-on impacts to the costs of providing distribution services. For example, transmission prices may increase in some regions as a result of them being subjected to higher (but more cost-reflective) charges under the AoB or deeper connection-based charging methodologies. Presumably these higher (but more cost-reflective) transmission prices flow through to higher (but more cost-reflective) retail variable charges and as a result lead to lower peak demands during times when the distribution network peaks, thus potentially reducing the cost of providing distribution services which would be an additional economic benefit.

Our analysis does not attempt to quantify this impact, due to the:

- Complexity of modelling the flow-on impacts of changing quantities on distribution businesses, particular as the impact is very much dependent on the location at which changes in demand occur (and whether they correspond with areas of congestion); and
- Likely low materiality of that benefit.

Therefore, this treatment is unlikely to change the broad conclusions contained in this report, in particular, that both of the two alternative options provide net economic benefits, relative to the current transmission pricing arrangements.

11.2. Retail

The way transmission services are priced in NZ will lead to changes in the retail price of electricity for different customers across NZ, relative to the status quo. Whilst this will have distributional impacts (ie, some customers may pay more than they otherwise would, whilst some customers might pay less than they otherwise would), any impact will be competitively neutral.

In particular, it is unclear why, or how, a change in the way transmission services are priced would:

- Create, or reduce, barriers to entry into the retail market; and/or
- Reduce retail competition.

Therefore, on face value, we see no material impact on the retail market stemming from any of the potential changes to transmission prices.

12. Conclusion

Both the AoB and deeper connection-based options for transmission pricing provide a positive economic benefit. The AoB charge exhibits a:

- Higher benefit-cost ratio than the deeper connection-based charge in all cases (with materially higher qualitative benefits, which are discussed below); and
- Positive benefit-cost ratio in all cases tested.

This predominantly occurs as a result of our assumption that the AoB charge will have significantly more coverage than the deeper connection-based charge and is also likely to avoid more dispute-related costs than the deeper connection-based charge.

The modelling indicates that there is a benefit from sending a cost-reflective transmission price signal to prospective electricity generators, with the benefit coming about as a result of the co-optimisation of transmission and generation by these prospective generators. The magnitude of this benefit is influenced by our calculation of the LRMC for transmission that is related to the siting and size of future generation investment, which in turn is predominately driven by estimates of future transmission investment within different regions within NZ provided by the Authority. It is also driven by whether or not some generating units at Huntly (Rankine units) are assumed be retained or not (as this drives the level of spare capacity in the generation sector). It is our understanding that there is significant uncertainty around whether the Huntly Rankine units will continue. For the purposes of the analysis we have assumed that there is an equal probability that the Huntly units will be retained or withdrawn and have therefore weighted the incremental benefits of the amended TPMs with and without the Huntly units equally.

A large proportion of the benefits result from the impact on future decisions of more efficient pricing of historical investments, in particular, the move to:

- Levying a smaller residual charge than is currently levied, and
- Basing its recovery on a measure of physical capacity, as opposed to the current RCPD charge.

The latter factor means that future consumption and investment decisions will not materially influence the level of physical capacity (and therefore the charge). This has led us to assume that this benefit would to be the same for both the AoB and deeper connection charge, as the use of physical capacity applies to both. Similarly, transitioning away from charging South Island Generators a HVDC charge based on their mean injections contributes significant economic benefits.

Beyond the quantitative discussion above, there are a number of other qualitative benefits attributable to the AoB charge relative to the deeper connection-based charge, including:

- The structure of the AoB charge – namely the fact that it is a two-part, fixed/variable tariff – means that the customer not only sees a total price that equates to the benefits they receive, but also a cost-reflective marginal price signal. In comparison, the deeper connection-based charge is assumed to simply allocate the full cost of an asset according to use, therefore, it does not send a truly marginal price signal. The lack of a marginal price signal is likely to lead to inefficient outcomes;

- The deeper connection-based charge is based on power flows, therefore it allocates charges according to use rather than benefit. Due to the physics of power flows, the benefit a customer gets from an asset in the grid may be quite different from the use they make of it. This disconnect between the charge a customer pays (based on use) and the benefit they get materially undermines the incentive benefits that can be obtained from service based and cost reflective pricing;
- Transpower would be required to determine the application of the deeper connection-based charge annually, based on a 5-year rolling average of flows. In practice, this creates a new “effective” per MWh charge to recover the cost of assets that have already been constructed. Using a variable price signal to recover the cost of historical investments will in theory lead to inefficient outcomes;
- The deeper connection-based charge is only levied on major users of an investment, therefore its coverage tends to be more localised relative to the AoB charge. This reduces the coverage of the price signal, as well as reducing any potential benefits that might ensue from incentivising greater scrutiny by end customers of Transpower’s proposed investments; and
- The deeper connection-based charge may, in theory, create a locational distortion. Whilst this is unlikely to alter the location decisions of distribution businesses, it may in theory influence their connection decisions, as well as the locational decisions of new generators and direct connect customers.

We have also considered the potential for the pricing options to lead to greater scrutiny of investments by stakeholders during the regulatory approval process, in particular, in terms of providing an incentive for them to reveal their willingness to pay for the services provided by Transpower. Quantifying a net improvement from increased scrutiny is problematic and our CBA has considered this matter qualitatively, but is nevertheless positive (and potentially material, even if it only comes about as a result of a small number of otherwise high cost inefficient projects not being completed).

13. Additional components

The second issues paper will also include draft TPM Guidelines for five other components that could each form part of either main option, as well one specific change in the Code. This section focuses on the application of these changes in the context of the AoB charge, since that is now the Authority's preferred approach. However, very similar comments would apply to their application with the deeper connection charge.

Transpower, in developing the TPM, could include any or all of the additional five components in the TPM if that would be practicable and consistent with the requirements of clause 12.89 of the Code. These include:

- Clarification of charging for staged commissioning of connection assets;
- A method for charging for transmission assets that were originally classified as connection assets but subsequently become non-connection assets
- Within the AoB and connection charges – actual cost-based operating and maintenance costs;
- Long run marginal cost charge; and
- kVar charge.

The proposed change in the Code relates to the loss and constraint excess and to power factor requirements.

13.1. Connection charge – clarification of charging for staged commissioning of connection assets

The TPM must include a methodology for charging for assets during staged commissioning if that would be practicable and consistent with the requirements of clause 12.89 of the Code.

More specifically, this option would involve clarifying in the Code that if assets are commissioned such that they provide connection services, they would be charged for as connection assets, including where it is anticipated that the assets would ultimately be configured to provide other services.

Before discussing the benefits and costs of this change, based on information provided by the Authority, it is our understanding that the High Court has already found that the interpretation of the Code, whereby assets that met the connection definition should be charged for as connection assets for that period of time – even if by the time of completion of the project, the assets are joined so that they no longer met the definition of connection assets.

In this context, the problem definition appears to be that the current interpretation of the Code could be strengthened by explicitly addressing this requirement in the wording of Code.

Further, we consider that the incremental costs of making this change would be immaterial – as all of the information is current being captured, reported and priced.

Therefore, in conclusion, it would appear to us to be self-evident that the benefits of providing Transpower with the option of making this change in the future would accrue positive net benefits. This is because the incremental costs of making the change are likely to be immaterial. Removing any ambiguity in the current Code regarding how it should be implemented, should provide long-term economic benefits to all parties operating in the electricity industry.

13.2. A method for charging for transmission assets that were originally classified as connection assets but subsequently become non-connection assets

The TPM must include a method for charging for transmission assets that were originally classified as connection assets but subsequently become non-connection assets, even though they continue to provide connection services, if that would be practicable and consistent with the requirements of clause 12.89 of the Code.

It is our understanding that recent events have brought this issue to the Authority's attention. In particular, a transmission customer has connected two connection assets to form a loop. Prior to the construction of this line, those substations comprised connection assets and would be subject to connection charges.

Therefore, whilst the asset itself is funded outside the TPM, the current way connection assets are characterised in the TPM means the connection assets that have been joined by the investment would become interconnection assets, and so funded through the TPM.

In OGW's opinion, there are likely to be net benefits in the guidelines requiring Transpower to provide clear rules about whether and to what extent connection assets that are connected by a new line become interconnection assets. The treatment under the TPM does not promote efficient investment as it provides a mechanism for the historical investments associated with connection assets that are being used to service individual customers to become socialised. More importantly, this treatment may might mean that future investment is skewed away from efficient levels, if proponents consider the possibility of this treatment in the investment decision, and this leads to inefficient investment options being proposed.

13.3. Area-of-benefit and connection charges – actual cost-based operating and maintenance costs

The TPM must include a method for the allocation of operating and maintenance costs for an asset in relation to which the area-of-benefit charge or connection charge applies to parties that pay charges in relation to that asset, if that would be practicable and consistent with the requirements of clause 12.89 of the Code.

The economic benefits stemming from this arrangement would in theory be that the party causing the costs to be incurred would be faced with a more accurate price signal, relative to the current approach, whereby the customer faces an "average" price signal. In theory, this should result in:

- Direct benefits, in that customers may be able to change their behaviour in response to that price signal, such that the overall economic cost of providing electricity services reduces; and
- Indirect benefits, in that customers may subject these costs (and the underlying driver of those cost) to more scrutiny as a result of being charged them, which may lead to alternative (more efficient) options being implemented.

Obviously, there will be some costs associated with accurately identifying the cost of operating and maintaining particular assets. For example, it is likely that service crews would be working on multiple assets in any given day, hence this change may necessitate changes in the way employees who work in the field record their time as well as other direct costs incurred in undertaking field work. It may also require back-office changes to processes and procedures, as well as IT systems.

These will all be important issues that Transpower would need to give consideration to when assessing whether this change would be practicable and consistent with the requirements of clause 12.89 of the Code. However, these issues don't dissuade us from concluding that there would likely be net benefits in providing Transpower with the option to undertake this assessment in the future.

13.4. Long run marginal cost charge

The TPM must include an LRMC charge or charges if that would be practicable and consistent with the requirements of clause 12.89 of the Code.

The economic benefit of implementing an LRMC based charge will be a function of:

- The costs of administering and implementing the LRMC based charge;
- The benefits of having a current price signal to supplement nodal prices in circumstances where investment might otherwise proceed inefficiently;
- The benefits of sending that *forward-looking* price signal regarding the marginal cost of serving future *demand*[75], with this in turn being a function of:
  - The difference between the current marginal price signal, and the marginal price signal that would result from using the LRMC as the basis for it; and
  - The elasticity of demand for transmission services.

75 Our view is that the primary benefit would be to signal the costs of future demand, because, for reasons outlined in other parts of this report, this is the cost driver that can be primarily impacted by end customers changing their consumption or investment behaviour in response to that price signal.

Presumably, the LRMC based price signal would be used to signal forward-looking capacity augmentations that would otherwise not be effectively signalled via the deeper connection-based charge or the AoB charge[76]. If so, then the benefits will be inextricably linked to the quantum of capex that will not be effectively signalled through the 2 main options. As discussed previously, it is our understanding that the AoB charge fully covers all future demand-related capital expenditure but the deeper connection charge does not. For example, the deeper connection-based charge incorporates a cut-off of HHI=2000, below which, capacity related investments (likely to be those serving multiple regions) would not be recovered through the deeper connection-based charge. There is also a risk that even within these HHI bounds, users may not believe that that their behaviour will alter the timing of the new asset investment, due to the indivisibility of the asset (ie, there are multiple users of the asset, and any response they make may not change the size or timing of the investment).

On face value, under both pricing options:

- There will be some capacity related expenditure that is driven by peak congestion that may be able to be signalled through a LRMC base charge; and
- The cost of calculating and sending an LRMC based price signal to transmission customers is likely to be relative minor.

Therefore, we consider there are likely to be net benefits in providing Transpower with the option of introducing a LRMC based charge in the future.

13.5. kVar charge

The TPM must include a kVar charge on reactive load if that would be practicable and consistent with the requirements of clause 12.89 of the Code.

A kVar charge would be intended to signal the value of correcting power factors in order to defer or avoid future static reactive investment. The benefits of a kVar charge are inextricably linked to power factors, and more particularly, whether power factors are less than unity. Based on information provided by the Electricity Authority, it would appear that power factors have been improving, and trending towards unity in recent times.

That said, power factors can:

- Change over time; and
- Be different in different regions.

76 If this is not the case – ie, some capex is signalled via the AoB charge or deeper-connection charge as well as by a variable charge that is based on the LRMC of supply, then the price signal is potentially duplicated, which may lead to inefficient outcomes if customer's consider both price signals when determining their consumption or investment decisions. Following on from this, if there is a view that customers won't respond to that AoB or deeper-connection charge in certain circumstances (eg, due to the indivisibility of an investment), then from an efficiency perspective, capex that is consistent with those circumstances should be explicitly excluded from the definition of the AoB or deeper-connection price signal. If that capex is demand-related, then it could then instead be signalled via the LRMC based charged.

Given this, on the balance of probabilities, there would appear to be net benefits from providing Transpower with the option of proposing a variation in relation to an additional kVar charge should power factors deteriorate in the future. There would also be benefit in providing Transpower with the option of implementing this on a locational basis.

13.6. Loss and constraint excess

It is important that the combination of the loss and constraint excess (LCE) allocation and the charges under the Authority's TPM proposal are efficient. To facilitate this, it is our understanding that the Authority proposes that the Code be amended in a number of ways, including, but not limited to:

- Including a formula that determines the proportion of LCE to be allocated to connection and area-of-benefit assets, and how LCE is to be allocated within each group;
- For LCE allocated to a connection or area-of-benefit asset under (a), requiring Transpower to allocate the LCE to the customers that pay charges in relation to that asset, based on the proportion of charges for that asset that each customer must pay under the TPM; and
- Requiring that any remaining LCE be allocated to customers that pay the residual charge, such that each customer is credited LCE based on the proportion of the residual charge that the customer must pay under the TPM.

LCE allocation should return loss and constraint rental to the providers of an asset. The proposed TPM implicitly changes the provider by changing the amount to be paid by different parties. The principle for changes to LCE allocation appear to be aligned with the changes to TPM. While the 'devil will be in the detail' on face value, presuming that the administrative costs of such a change are immaterial, there would appear to be net benefits in implementing the proposed change in the Code.

13.7. Amending the Power Factor requirements

The Authority has proposed amending the Connection Code (incorporated by reference into the Code) to set the required power factor be relaxed to 0.95 lagging for all regions. The purpose of this is to simplify and clarify required power factors. It is also intended to provide a signal to Transpower that a kVar charge may be appropriate.

The benefit of this proposal is likely to be small but positive. However, the cost is likely to be minimal, so there would appear to be net benefits in implementing the proposed change in the Code

Appendix A: The basis for the LRMC of transmission estimates

A.1 Background

OGW has modelled the impact of a number of different factors on the LRMCs of providing transmission services, which in turn have been used in this CBA. The two key determinants are:

- The amount of transmission investment that will be required in the future and which will be driven by:
  - generation requirements, and
  - load requirements.
- Whether existing plants at Huntly are retained or not.

The results are reported in the body of this document.

All LRMCs have been calculated based on the Average Incremental Cost approach - which reflects the NPV (future capex and opex) / NPV (cost driver).

All capex related information, as well as underlying demand forecasts, have either been obtained directly from the Authority, or derived primarily from information provided by the Authority. The capex information that was provided by the Authority had already been split into:

- Load regions, being UNI, LNI, USI and the LSI, with the allocation based on the region that was driving the capital expenditure (as opposed to the region that where the capex was located), and
- Generation regions, again being UNI, LNI, USI and the LSI, with the allocation based on the location of the generation that was driving the capital expenditure to be incurred.

All raw LRMC calculations have been adjusted downward by 30% to account for the fact that our analysis is being undertaken over 19 years (due to data availability), yet these assets generally have lives of 50 years or more[77]. The load related LRMCs have also been adjusted downward to reflect advice from the Authority that some investments are based on changing patterns of demand caused by exit and entry of large plant; it is not all caused by standard percentage growth in demand in regions leading to capacity becoming constrained. The LRMC's revealed in other jurisdictions have also been considered when making this assessment.

In the base case, the load LRMC has been used in the CBA to assess whether there are other potentially more efficient investments in services or equipment that may otherwise substitute for transmission services. The generation LRMC has been used to assess whether future investment in electricity generation services is likely to be different, if prospective generators were faced with a price signal around the impact that the sizing, location and timing of their generation investment had on future transmission investments. The base CBA analysis reflects the 50:50 probability weighting of the outcomes resulting from assuming Huntly is retained and assuming it is not retained.

77 Broadly, this was done by estimating what the cost per MW was based on capex and demand data provided by the Authority, and then determining the difference between the annualised value for this figure, assuming a 19-year life relative to a 55-year life.

The other scenarios (eg, existing plants at Huntly are retained, but major capex is lower) have only been used for the purposes of sensitivity analysis.

A.2 Data Collection

This LRMC model is based on the following data:

- Capex – The Authority provided OGW with a capex data set, split out into base capex and major capex. OGW have only used major capex in its calculation of the LRMC in all scenarios, on the assumption that this capex is demand-driven, whereas base capex is assumed to be likely to be primarily related to other drivers (eg, replacement expenditure). The Authority split this capex between load and generation on a 60/40 basis;
- Growth in demand – The Authority provided OGW with a national and regional demand forecast for a 50-year period; and
- Growth in generation – existing grid capacity (MW, and MWh) estimates were derived from Transpower's Transmission Planning Report (2015)[78]. OGW used publically available information to allocate these starting capacities (MW and MWh) to each of the four previously mentioned regions. OGW then applied the same growth rate as it has for growth in customer demand (which was based on information provided by the Authority) to determine growth in generation within each region.

A.3 Load LRMC

OGW has calculated the LRMCs for the UNI, LNI, USI and the LSI.

A.3.1 Capex

OGW used capex data provided to by the Authority, which included the 60% split for load, and which allocated this capex into the four aforementioned regions.

As mentioned in the background section, we only included major capex in the LRMC calculation, on the assumption that this capex was the category of capex that would primarily be driven by growth in peak demand.

A.3.2 Demand

OGW applied the implied growth factor from Transpower's National-Regional Peak Demand Forecasts Feb-2015 model. We applied the winter 50P of forecast peaks, as our basis of the demand forecast for modelling period.

OGW split the demand data set into four regions, covering:

- UNI – Northland, Auckland;
- LNI – Waikato, Bay of Plenty, Hawkes Bay, Taranaki, Central Districts, Wellington;
- USI – West Coast, Nelson-Marlborough, South Canterbury, Canterbury; and
- LSI – Otago-South

A weighted average conversion factor was estimated and applied to the Authority's demand forecast to convert the reported MW into GWh for the LRMC $/MWh calculation.

78 https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPR2015CompleteFINAL.pdf, p. 30

This conversion factor is based on the type of generation and was estimated by calculating a conversion factor by type of generation. We then calculated a weighted conversion factor for the different types generated within each region, ie, UNI, LNI, USI, LSI.

A.4 Generation LRMC

A.4.1 Capex

OGW utilised the capex data set provided by the Authority, which included the 40% split for generation.

As was the assumption for load, we only utilised major capex, as this was assumed to be demand-related.

A.4.2 Demand

The basic assumptions for the generation capacity calculations are similar to the load volume calculation, in that:

- We applied the same regional split as for the load calculations; and
- We also applied the same weighted conversion factor (MW to GWh) as for the load calculations, which was then applied to the sum of existing capacity in each region.

The generation capacity calculations are based on Transpower's existing grid connections data. To determine the increase in generation over the evaluation period, we assumed that existing generation capacity increases at the same rate as demand, thus we applied the same growth rate as is applied for load in Transpower's National-Regional Peak Demand Forecasts Feb-2015 model. This is the growth factor from the Winter 50P of forecast peaks. This is generally between 1% to 1.5% per annum.

Appendix B: The basis for the costs of embedded generation and storage

B.1 Introduction

Our determination of the LRMC of embedded generation and storage is based upon publicly available data and OGW project experience. We did not conduct widespread consultations to source primary data, as this was not feasible in the time available.

The embedded options considered were diesel and natural gas reciprocating modular generator sets (1-2MW in size) up to 30MW in aggregate capacity which could be connected at distribution level to supply peaking network support.

The emerging technology of Li-Ion utility scale storage is also examined as an embedded alternative to network augmentation. Due to the rapid reducing capital cost and experience curve for the technology a capital cost for 2015 and 2025 have been analysed.

B.2 General Assumptions

All installations are considered to operate as peaking plant and operate for 2% of the year.

Determination of annual capital charge is based on a pre-tax nominal return of 8%.

B.3 Embedded Reciprocating Generation Assumptions

The following table highlights the key embedded reciprocating generation assumptions.

Table 31: Embedded Reciprocating Generation Assumptions

Item	Units	2015	2025	Source
Capex	$/kW	$550	$1,320	OGW
Construction time	yrs	1	1	OGW
project life	yrs	15	15	OGW
Fixed Operating and Maintenance (FOM)	$/MW	$30,000	$30,000	OGW
Variable Operating and Maintenance (VOM)	$/MWh	$15	$10	OGW
Fuel consumption				OGW
-Diesel		250 L / MWh		
-Gas		11 GJ / MWh		
Fuel cost				NZ Ministry of Business, Innovation and Employment
-Diesel		$1/L		
-Gas		8 $/GJ		
	$/MWh	$250.00	$88.00	Calculation
VOM total		$265.00	$98.00	Calculation
hours operation pa	pa	2%	2%	OGW

Fuel costs	$NZ pa/MW	$43,800	$15,418	Calculation
VOM costs	$NZ pa/MW	$2,628	$1,752	Calculation

B.4 Energy Storage Assumptions

The base case of energy storage cost has been sourced from Lazard's levelised cost of storage analysis – version 1.0 for peak operation[79]. The report provides low and high costings and for the analysis presented in this report the average has been used.

Battery and other component price forecasting has been based on a presentation that Bloomberg New Energy Finance (BNEF) presented at the 2015 Australian Energy Storage Conference and Exhibition[80].

It has been assumed for the calculation of comparative costs that the unit of energy storage is able to supply the power output for 4 hours continuously. For example a 1MW connected capacity will be supported by a 4MWh battery installation. Exchange rate assumptions are NZ/US = 0.7.

Table 32: Energy Storage Assumptions

Item	Units	2015	2025	Source
Capex ($2015)	$/kW	$5,380	$2,260	Lazard & BNEF
Construction time	yrs	2	2	AEMO
project life	yrs	20	20	AEMO
Fixed Operating and Maintenance [1]	$/MW	$30,000	$30,000	AEMO
Variable Operating and Maintenance[1]	$/MWh	-	-	AEMO
Round trip efficiency[2]		88%	88%	OGW
Electricity costs[2]	$/MWh	140	140	Ministry of Business, Innovation and Finance
hours operation	pa	2%	2%	OGW
Annualised opex	$NZ pa/MW	$33,345	$33,345	Calculation

1) Both FOM and VOM are based on the assumption that there are similar technologies (no moving parts, inverters, power equipment) to a utility solar PV installation.

2) It is assumed the DC roundtrip efficiency is 90% and the inverter efficiency is 98%.

79 https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf

80 Bromley, 3 June 2015, Australian and Global Outlook for Energy Storage Deployment.

Appendix C: The basis for the costs of demand-side response options

The estimate of the costs of DR was taken from recent Transpower experience, as reported in its *2013 Demand Response Programme Report* (April 2014)[81]. As noted in that report:

> *Transpower ran a commercial demand response programme between July and December 2013, using its new Demand Response Management System (DRMS).*
>
> *The programme went a long way to meeting its objectives. There were 8 participants with 134 MW of DR registered at the commencement. . . . Over the programme, there were 20 Demand Response events successfully called, with the largest DR call of 175 MW . . . Natural price points were found for the types of DR provided, and importantly - non-generation demand response was priced competitively compared to demand response through generation.*
>
> *Through the testing it was shown that participant fatigue - the point at which participants cease responding to DR events either through lack of ability or willingness - was not apparent. Indeed, participants' feedback at the end showed an overall positive attitude towards the programme and an expectation that they would participate in future demand response programmes.*

Highlights of the results of the 2013 programme noted in the report are shown in the table below:

Table 33: Demand Response Assumptions

Item	Value
Total DR capacity registers	134 MW
Total cost of the programme	$745,000
▪ Availability payments	▪ $195,000
▪ Dispatch payments	▪ $550,000
Number of dispatch calls	20
Average duration	2 hours
Average DR delivered	38 MW
Annualised cost of demand reduction delivered	$19,605 per MW
Net reduction in energy consumed	1,583 MWh
Average cost of net energy reduction	$470 per MWh

81 Available at https://www.transpower.co.nz/news/demand-response-programme-summary-report-released

It should be noted that:

- The calculation of the annualised cost of demand reduction delivered and the average cost of the net energy reduction of the programme are both based on the total programme cost of $745,000; and
- The amount of DR available in any locality will be limited, but in a relatively large transmission area (which is likely to represent a representative cross-section of the electricity system as a whole) a value of approximately 8% is likely to be a reasonable estimate, based on experience elsewhere.

Appendix D: Key assumptions used in modelling

In quantifying the impacts of the different options, a number of assumptions were required. The following table provides a summary of those key assumptions.

Table 34: Summary of the key assumptions used in the modelling

Element	Assumption	Source
Demand-driven capital expenditure	▪ Scenario 1a (Case used in body of report) - $100m p.a. of capex over the period ▪ Scenario 1b - $100m p.a. of capex over the period except for a 5-year period where it increases to approximately $200m p.a. ▪ Scenario 2a (reduced capex) - $50m p.a. of capex over the period.	▪ Capital scenario information provided by the Authority[82] for years 1-20 ▪ OGW applied a consistent approach to the two capital program scenarios from years 21-30
Discount rate	8% real pre-tax	Electricity Authority, Transmission Pricing Methodology: CBA - Working Paper, September 2013, p. 32.
Elasticity of demand	-0.4%	OGW review of available literature (see below for more details)
Capital Recovery Rate	8.5%	Consistent with assumptions used by Electricity Authority for their modelling of the TPM[83]
Depreciation Rate	2%	OGW assumption based on estimated standard life of transmission assets (50 years)
Maintenance Allowance Rate	4%	Consistent with assumptions used by Electricity Authority for their modelling of the TPM[84]
Volume forecasts	Annual growth rates	Electricity Authority[85]
Investment coverage of pricing methodology options	Area of Benefit (100%) Deeper Connection (50%)	OGW Assumption, based on qualitative description of coverage of options provided by the Authority
Term for analysis	20 Years	Electricity Authority, Transmission Pricing Methodology: CBA - Working Paper, September 2013, p. 32.

82 Email from Blair Robertson of the Electricity Authority to Rohan Harris of OGW et al on 8/03/2016

83 Email from Alistair Dixon of the Electricity Authority to Rohan Harris of OGW et al on Tue 3/11/2015 12:42 PM [“Spreadsheet of TPM options for 2nd issues paper”.xls]

84 Ibid

85 See Appendix A.

Element	Assumption	Source
Forecast Regional Coincident Peak Demand	Applied historical average	OGW Analysis of historical data published by Transpower
Transmission proportion of retail volumetric component	- Overall proportions of average bill - Retail bill is 50% volumetric	- Commerce Commission, Electricity Distribution Business Price-Quality Regulation 1 April 2015 Reset Model 22: Data for impact on consumer bills - Final Determination version - OGW Assumption
Potential offset of capital expenditure from demand side response	8%	OGW Analysis - based on: - Information published by the AEMC[86], which estimates the demand response in US electricity markets at on average 7.2% of total demand; the demand response capability in the Western Australian Market to be 8.2% of total demand; the demand response in the Commercial and Industrial sector of the Eastern Australian market to be between 6% and 8% of total demand. - OGW assessment of AusNet Services, a distribution business in Victoria, Australia, Critical Peak Demand tariff that has generated 102MW of demand response on a total peak demand of 1800MW (5.5%) - from only around 2500 Commercial and Industrial customers[87].
Size of potential deferrals	5*$40m project deferrals of 1 year (Base CBA) 5*$20m project deferrals of 1 year (reduced capital profile sensitivity) 3 *$40m and 2*$60m project deferrals of 1 year (Scenario 2 - sensitivity analysis) 3*$20m and 2*$30m project deferrals of 1 year (Scenario 2 reduced capex sensitivity)	OGW Assumption
Buffer allowance on transmission costs for alternative generation	15%	OGW Assumption
Adjustment to LRMC estimate for non-shared network demand-driven capital expenditure	40%	OGW estimate - based on high level guidance from the Authority regarding the existing of such expenditure, and reference to international observations on benchmark LRMCs
Adjustment to LRMC estimate for spare	30%	OGW estimate - See Appendix A for details

86 "Appendices - *Power of choice review - giving consumers options in the way they use electricity*", 30 November 2012 (section C5)

87 http://www.aer.gov.au/system/files/AusNet%20Services%20Tariff%20Structure%20Statement%20proposal%20-%2026%20October%202015_0.pdf

Element	Assumption	Source
capacity		
Assumptions for RCPD Benefit		
RCPD Charge (using n=100) ($/MWh)	$2,312	Transpower[88]
Number of hours of operation of distributed generation/demand response	100 hours	OGW Assumption
Cost of diesel generation based on 100 hours ($/MWh)	$1,125	OGW Analysis based on cost information outlined in Appendix B
Cost of demand-response based on 100 hours ($/MWh)	$196	OGW Analysis
Proportion of Avoided Cost of Transmission (ACOT) payments that reflects the underlying cost of producing the energy	50%	OGW Assumption, based on a linear production function.
Natural cap in proportion of load supplied by diesel generation	5% of demand in any one year	OGW Assumption
Natural cap in proportion of load supplied by demand-response	5% of demand in any one year	OGW Assumption
Number of years to reach natural cap	20 Years	OGW Assumption

In relation to the estimate of the elasticity of demand, OGW has considered a range of estimates and information when deciding upon its -0.4 estimate. These include, amongst other things:

- Elasticity estimates used by the Australian Energy Market Operator (AEMO), which has recently reported elasticities of demand of -0.32311 for Queensland, -0.37243 for New South Wales and -0.21751 for Victoria[89]; and

88 https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPM-Attachment-B%20background-supporting-analysis.pdf

89 AEMO, *"Forecasting Methodology Information Paper, 2015 National Electricity Forecasting Report",* July 2015, page 14

- Information sourced from a paper by NERA Economic Consulting in the US, which summarises the results of previous studies that have been undertaken in the US into the long-run own-price elasticity of demand for electricity services[90]. The results of these studies range from -0.26 through to -3.26, with the average across the 11 reported studies being -0.93. When two "outlier" studies are removed, this reduces to -0.59; and
- Information from the NZ Electricity Authority's previous modelling on this topic, which used elasticities that ranged from -0.26 (Mass-market consumers and Other Industrials) to -0.087 (Inelastic industrials) and -0.78 (Elastic industrials).[91]

90 NERA, "*An Econometric Assessment of Electricity Demand in the United States Using Panel Data and the Impact of Retail Competition on Prices*", June 2015, page 2

91 http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c13929

Appendix D Indicative charges

D.1 This Appendix provides more detail on the modelling results, over and above what is provided in the main text.

D.2 The modelling results provide broadly indicative charges, and are intended to provide a sense of the magnitude of the change in charges that could be expected under the Authority's proposal if the area-of-benefit charge were applied using the vSPD method. It is important to note that the draft guidelines do not specify the method used to determine area-of-benefit charges, so Transpower may propose another method for this. Accordingly, actual charges may differ from what is presented in this Appendix.

D.3 The modelling results are subject to a number of qualifications and assumptions. These include:

(a) The counterfactual (or 'no investment') scenario cases assume that specified eligible transmission investments have not proceeded. The vSPD outputs from these scenarios are compared to base case scenarios to estimate the incidence of benefits for each eligible investment. The counterfactual cases include virtual price offer (VPO) resources which are intended to simulate the outcomes that would have occurred in the absence of the eligible transmission investments. VPO resources are used because it would be unrealistic to simply assume that there is a large increase in non-supply in the absence of particular transmission investments.

(b) The results are based on one year of vSPD modelling, and therefore do not necessarily reflect the full range of hydrology, or other market conditions that could occur. If the vSPD method were used to apply the area-of-benefit charge, the Authority would expect that multiple years would be modelled that incorporated a full range of hydrology and market conditions.

(c) Transmission constraint limits for the counterfactual (or 'no investment') scenarios have been estimated from information available to the Authority. If the proposal is implemented, and if the vSPD method is used to apply the area-of-benefit charge, the Authority expects that more detailed analysis would be undertaken by Transpower to determine the constraint limits.

(d) Contingencies such as unexpected losses of transmission circuits or generators have not been modelled. This means that the full reliability benefits of investments are not captured in the results.

D.4 Further information on the modelling of indicative charges, including key assumptions, is set out in Appendix B.

D.5 The LRMC and kVar charges have not been modelled (see Appendix B for more information on the modelling assumptions).

D.6 The data underlying these tables and graphs are provided at the following page on the Authority's website.

Modelled charges

D.7 This section of the Appendix provides breakdowns of the incidence of modelled transmission charges between parties. All results shown are net of LCE.

D.8 The charges shown for load parties do not include any allowance for pass-through of charges by generation parties.

Table 8: Modelled charges for each option ($m per year)

	Status quo (Post 2017 TPM)[272]	Proposal	Difference
NI Generation	0	*12*	12
SI Generation	140	*58*	-82
UNI mass-market load	206	*299*	93
LNI mass-market load	234	*195*	-39
SI mass-market load	131	*141*	10
NZAS	61	*40*	-21
Other major industrials	22	*49*	27

Table 9: Modelled charges for each option, in fully variabilised terms ($/MWh)

	Status quo (Post 2017 TPM)	Proposal	Difference
NI Generation	0.0	0.5	
SI Generation	7.9	3.3	-4.6
UNI mass-market load	20.3	29.4	9.1
LNI mass-market load	20.5	17.1	-3.5
SI mass-market load	14.0	15.0	1.0
NZAS	12.2	8.02	-4.2
Other major industrials	5.9	14.5	8.6

Note: The figures in the above tables represent:

- *total charge divided by generation injection, for generators*
- *total charge divided by load offtake, for major consumers*
- *total charge divided by approximate gross electricity consumption, for distributors.*

[272] The reference in Table 9 and subsequent figures to "Status quo (Post 2017 TPM)" is the TPM that will be in place from 1 April 2017 that incorporates the changes resulting from Transpower's 2014/15 TPM operational review.

D.9 Table 10 breaks down modelled charges between individual parties, for each option and the status quo. Table 11 shows the equivalent information, with charges presented in fully variabilised terms.

D.10 As set out in Appendix B:

(a) some geothermal power plants (such as Nga Awa Purua) are separated out for ease of reference

(b) some industrial consumers are also separated out for ease of reference even though, in practice, their transmission charges might be paid indirectly through a network or retailer.

D.11 The modelled charges on distributors in these tables do not reflect that some distributors make ACOT payments to embedded generators. As a result, ‘status quo’ charges may appear anomalously low (comparatively) for networks that include substantial amounts of embedded generation, relative to their amount of load (such as Top Energy or Westpower).

Table 10: Modelled charges for each option ($m per year)

	Status quo (Post 2017 TPM)	Proposal
distributors		
Alpine Energy	10.5	9.9
Aurora Energy	21.6	19.31
Buller Electricity	1.277	1.79
Centralines	2.0	1.6
Counties Power	10.2	12.5
Eastland Network	5.3	4.2
Electra	6.4	7.3
Electricity Ashburton	3.6	12.0
Electricity Invercargill	5.5	3.6
Horizon	3.2	6.9
Lakeland Network	0.2	0.2
Mainpower	9.5	8.3
Marlborough Lines	6.6	4.9
Network Tasman	10.7	10.3
Network Waitaki	3.2	4.0
Northpower	13.0	20.6
Orion	63.9	47.6
OtagoNet JV	4.0	4.7
Powerco	74.2	72.5
Scanpower	1.5	1.2
The Lines Company	3.7	5.2
The Power Company	9.7	10.1
Top Energy	4.3	9.5
Unison	30.5	24.8
Vector	178.8	256.7
Waipa Power	6.4	6.0
WEL	19.7	22.1
Wellington Electricity	55.2	43.2
Westpower	1.6	4.7

	Status quo (Post 2017 TPM)	Proposal
Generators		
Contact	32.6	16.6
Genesis	6.8	5.4
Meridian	96.7	39.3
Mokai JV	0.0	0.2
Mighty River Power	0.0	4.1
Nga Awa Purua JV	0.0	0.5
Ngatamariki	0.0	0.3
Pioneer	0.4	0.1
Todd	0.0	0.1
Trustpower	3.7	3.0
Major industrials		
Carter Holt Harvey	4.1	6.1
Daiken MDF	0.9	0.8
Kiwirail	0.5	2.3
Methanex	0.7	0.7
Norske Skog	0.0	6.8
NZ Steel	4.6	16.7
NZAS	60.8	40.0
Pan Pac	4.3	6.2
Rayonier	0.7	0.6
Refinery	3.2	5.9
Winstones	3.2	2.8

Figure 21: Indicative customer charges ($m/year)

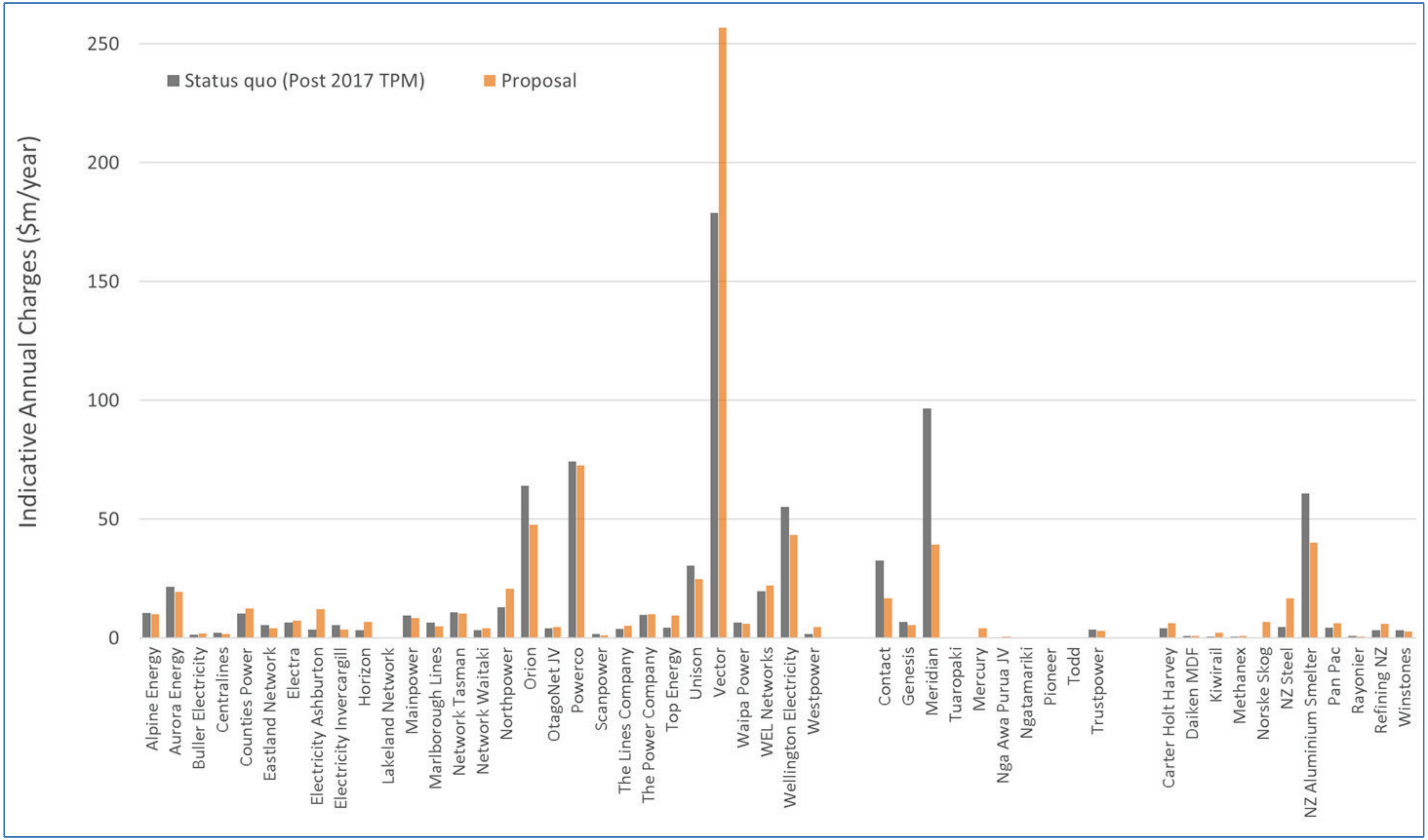

Table 11: Modelled charges for each option in fully variabilised terms ($/MWh)

	Status quo (Post 2017 TPM)	Proposal
Distributors		
Alpine Energy	13.3	12.5
Aurora Energy	16.0	14.3
Buller Electricity	11.9	16.8
Centralines	18.1	14.0
Counties Power	18.0	22.1
Eastland Network	17.6	13.8
Electra	14.7	16.9
Electricity Ashburton	5.8	19.2
Electricity Invercargill	21.5	13.9
Horizon	6.5	13.8
Lakeland Network	18.5	14.9
Mainpower	17.3	15.1
Marlborough Lines	16.9	12.6
Network Tasman	14.7	14.1
Network Waitaki	11.9	14.7
Northpower	17.2	27.1
Orion	19.7	14.7
OtagoNet JV	9.4	11.1
Powerco	16.9	16.6
Scanpower	18.2	14.2
The Lines Company	12.6	17.8
The Power Company	12.6	13.0
Top Energy	12.0	26.4
Unison	18.7	15.2
Vector	21.3	30.5
Waipa Power	17.1	15.9
WEL	15.8	17.8
Wellington Electricity	22.4	17.5
Westpower	5.7	16.4

	Status quo (Post 2017 TPM)	Proposal
Generators		
Contact	3.0	1.6
Genesis	0.9	0.7
Meridian	7.4	2.9
Mokai JV	0.0	0.2
Mighty River Power	0.0	0.9
Nga Awa Purua JV	0.0	0.5
Ngatamariki	0.0	0.5
Pioneer	7.5	2.1
Todd	0.0	0.1
Trustpower	1.9	1.5
Major Industrials		
Carter Holt Harvey	6.8	10.4
Daiken MDF	12.7	11.0
Kiwirail	14.3	57.2
Methanex	12.9	13.2
Norske Skog	0.1	14.3
NZ Steel	5.2	15.7
NZAS	12.7	8.02
Pan Pac	6.7	11.6
Rayonier	13.8	11.5
Refinery	12.2	22.3
Winstones	13.8	11.8

Note: The figures in the above table represent:

- *total charge divided by generation injection, for generators*
- *total charge divided by load offtake, for major consumers*
- *total charge divided by approximate gross electricity consumption, for distributors.*

Examples of how and why the proposed TPM impacts on charges

D.12 This section provides some examples of how and why charges in different parts of the country change in different ways.

Electricity Ashburton case study

D.13 A very small fraction of Electricity Ashburton's proposed (indicative) charges—less than 20%—will be allocated through the area-of-benefit charge. This is not because Electricity Ashburton does not benefit from the grid, but because it is not a noteworthy beneficiary of the recent major grid upgrades that are proposed to be included in the area-of-benefit charge initially. These investments mainly serve the North Island, and in particular the upper North Island. The small fraction of the area-of-benefit charge that Electricity Ashburton does face is due to it benefiting from reduced electricity losses. Reduced loss benefits from transmission investments are low in dollar terms but they are more generally received across the grid. As a new TPM beds in and as new investments are included in the area-of-benefit charge, Electricity Ashburton will receive a greater portion of its charges through the area-of-benefit charge–to the extent that it benefits from new investments, and its residual charge will reduce as the residual pool reduces over time.

D.14 The modelled increase in its indicative charges from approximately $5.80/MWh under the current TPM to $19.20/MWh, is due to Electricity Ashburton having one of the lowest charges in $/MWh of all distributors under the current TPM. Electricity Ashburton's indicative charges under the Authority's proposal are lower than the average of all distributors of $20.04/MWh.

D.15 Electricity Ashburton's charges are low under the status quo TPM because the current interconnection charge is a peak charge which is generally calculated on winter peaks and Electricity Ashburton's peaks are typically in the summer due to the volume of irrigation serving the region.

D.16 The Authority has moved away from a peak charge for the residual because a peak charge is efficient only where there are costs that can be avoided by avoiding peaks. Imposing a peak charge on a system where there is no significant new investment to avoid is inefficient because it discourages use of the grid when that use would be efficient. The Authority is proposing a capacity-based charge for the residual precisely because it is difficult to avoid—it is less distortionary because it spreads the fixed cost in a way that is unrelated to how much customers use the asset.

Kiwirail case study

D.17 KiwiRail's current transmission charges are calculated at $0.5m pa, increasing to an estimated $2.3m pa under the Authority's proposal – a 360% increase. The main reason for KiwiRail's increase in charges is its low load factor, or its high level of capacity to take electricity relative to its average demand. As a result of its load factor, KiwiRail is expected to receive a relatively higher portion of the proposed residual charge which is based on a transmission customer's physical capacity to take electricity. The Authority understands that KiwiRail requires a high level of capacity because of its traction motors which are used to propel electric trains. Traction load, which is highly intermittent load and gives rise to a requirement for spare capacity, currently accounts for around 60% of KiwiRail's total load.

D.18 While the increase is substantial in percentage terms, transmission charges of $2.3m pa represent less than 0.5% of KiwiRail's total annual operating expenses of $630.1m for the year ended 31 March 2015. Further, transmission costs are relatively modest compared to KiwiRail's total 'fuel and traction' costs which were $92.9m in that same year and which have fluctuated considerably over the last three years – $92.2m, $114.9m and $57.2m in the financial years ending in 2015, 2014 and 2013 respectively.[273]

D.19 Electricity costs appear to be a smaller proportion of KiwiRail's costs than more energy intensive industries, where transmission costs are a much larger component of overall costs. For example, KiwiRail's modelled transmission cost to gross income ratio of approximately 0.3% ($2.3m/$720.6m in sales)[274] is small compared to NZAS's 4% ($40m/approximately $1 billion in sales).[275]

North Island Grid Upgrade case study

D.20 The North Island Grid Upgrade (NIGU) was a significant investment for the national grid, costing $894m, or about 20% of Transpower's regulatory asset base (RAB) of $4,610.2 million in 2015/16. The primary justification for the NIGU project was improved reliability in the upper North Island region; if the project did not promote this objective it would not have proceeded. The annual cost of the investment to Transpower's customers is calculated at approximately $130m pa, a cost that is being spread across all of Transpower's interconnection customers under the current TPM.

D.21 Under the Authority's proposal, the cost of NIGU would be recovered through the area-of-benefit charge. Based on the Authority's indicative modelling of charges which uses vSPD to calculate beneficiaries, the benefits of NIGU greatly exceed the costs under the 1900MW constraint scenario (refer Figure 35). For example, Vector's annual modelled benefit alone is greater than $250m against a total annual cost of NIGU of approximately $130m. Note however that the quantum of annual benefits of NIGU is highly sensitive to constraint assumptions around NIGU–the tighter the constraint the higher the benefits calculated by vSPD. This is because if the constraint level is tighter, the network would be less able to supply the Auckland region without a significant loss of reliability.

D.22 The Authority has observed that the total annual benefit of NIGU has increased substantially. The Authority's indicative modelling takes account of the decommissioning of the Otahuhu B and Southdown thermal generators.

D.23 The modelling demonstrates that upper North Island loads are the main beneficiaries of NIGU and are therefore the logical recipients of the charges for NIGU.

D.24 Where a new generator locates to the south of Auckland, depending on the method Transpower employs to calculate beneficiaries, that generator will likely be seen as a beneficiary of NIGU if it supplies the Auckland region. However, if a new generator locates in Auckland, it will likely only benefit to the extent that it supplies electricity to the north or south of the Auckland region. This is an efficient location signal as it incentivises generators to locate close to major loads when that is efficient.

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[273] Source: KiwiRail Annual Reports, years ended 2015 and 2014.

[274] *Ibid.*

[275] Source: http://www.nzas.co.nz/

OtagoNet case study

D.25 OtagoNet's current interconnection charge which is based on a peak charge is modelled at $9.40/MWh, well below the distributor average of $17.87/MWh under the status quo. The proposed TPM allocates the residual charge on capacity which is considered to be more difficult to avoid than a charge based on volume. OtagoNet's expected combination of area-of-benefit and residual charges under the proposed TPM is modelled at $11.10/MWh, the lowest charge in $/MWh terms of all distributors. The reason for OtagoNet's relatively low charge is, firstly, because OtagoNet has a low exposure to the area-of-benefit charge, and secondly, because it has a comparatively high capacity factor, ie, it has a comparatively lower level of spare capacity than other distributors. Distributors with high capacity factors typical enjoy more stable levels of demand while distributors with lower capacity factors typically experience more volatile or peakier demand and require additional capacity to serve this demand.

Westpower case study

D.26 Westpower's proposed charges in $/MWh terms are modelled at $16.40/MWh compared to charges of $5.70/MWh under the existing TPM. While this represents a substantial increase (188%), Westpower's charges in $/MWh under the current TPM are among the lowest of all distributors. This is because the West Coast region is well served by distributed generation which generates during peaks and allows Westpower to substantially avoid the current peak-based interconnection charge. Given there is no substantial transmission investment to avoid, there is very little cost to avoid. So a peak charge can encourage inefficient distributed generation investment, and reduces the base on which the fixed cost of the interconnected grid is recovered, which is likely to be inefficient.

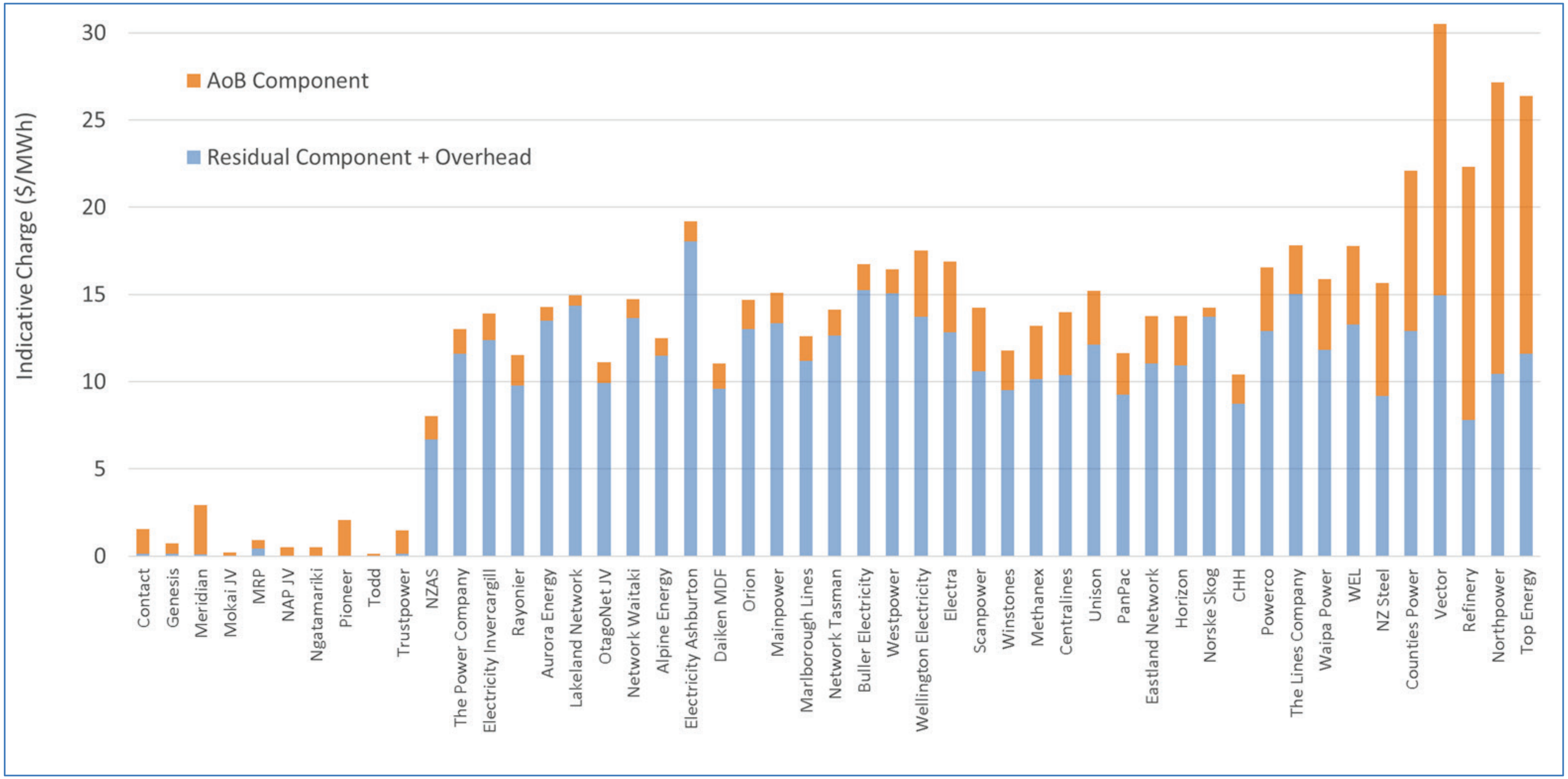
D.27 While Westpower's charges are expected to increase substantially, the increase is far more moderate than under the options explored in the Authority's TPM options working paper. Under the three options explored in that paper, Westpower's charges were anticipated to be between $30.50 and $31.10/MWh. Under the Authority's proposal the modelled charges of $16.40/MWh are lower than the average for distributors of $20.04/MWh.

D.28 Westpower will not qualify for a prudent discount to have its charges reduced. This is because, for distributors, the prudent discount policy effectively applies to the area-of-benefit charge only and there are no transmission assets which substantially serve the West Coast which are included in the area-of-benefit charge. In particular, the West Coast upgrade, a recent transmission investment undertaken to serve the now closed Pike River coal mine, was not included in the area-of-benefit charge under the Authority's proposal as it is under the proposed $50m threshold for application of the charge to historical investment. Accordingly, its costs would be recovered through the residual charge, so would be spread across all load customers.

Indicative Customer Charges, by Charge Component ($/MWh)

D.29 Figure 22 shows how the costs of investments required to transport power to the upper North Island are allocated to that region (note that the load customers are sorted geographically from south to north). This graph should be read in conjunction with the next graph which explains the reason for the variation in residual charges amongst customers.

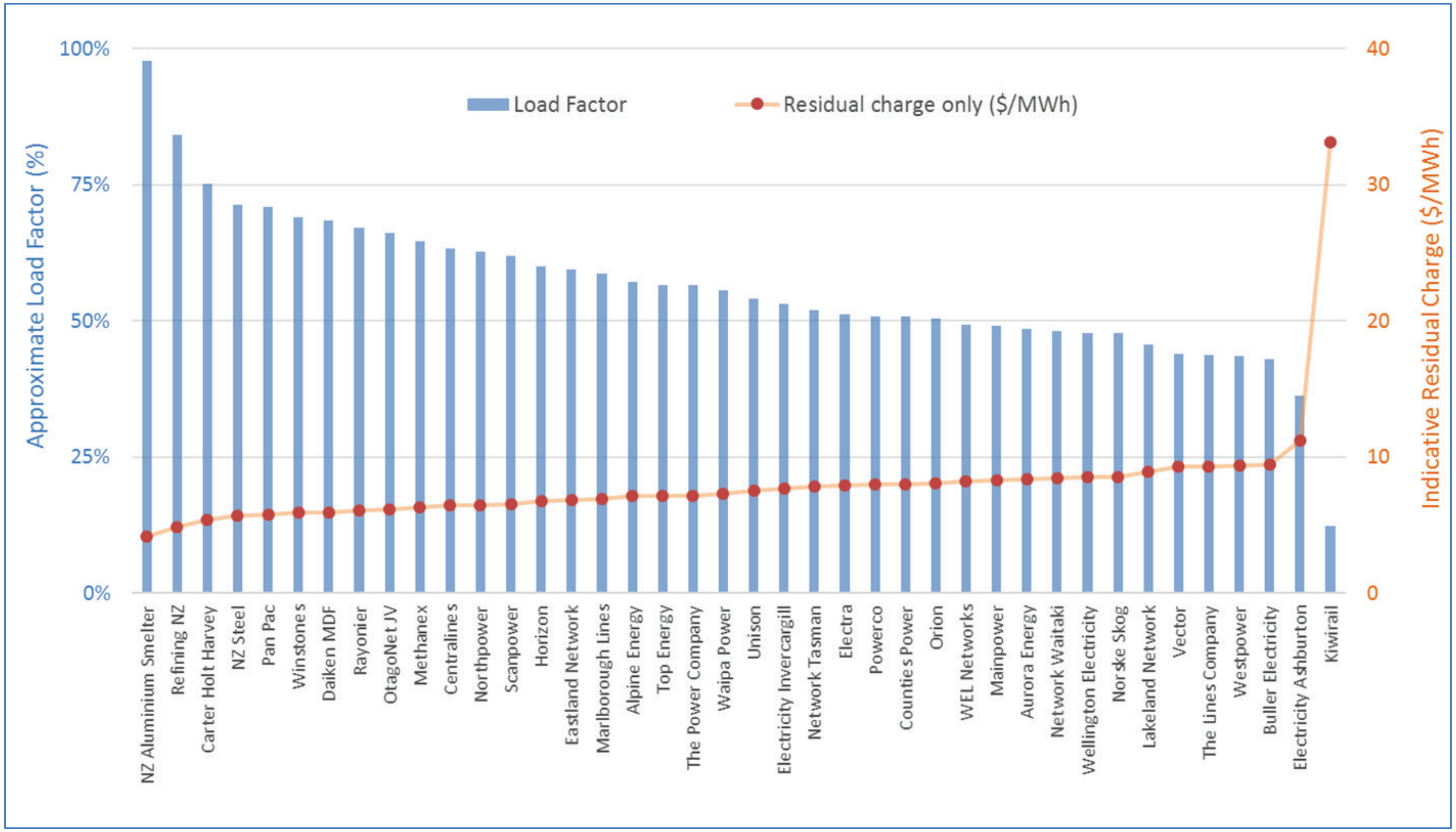
Figure 22: Indicative charges by component ($/MWh) – load sorted geographically from south to north



Effect of Customer Load Factor on the Residual Charge

D.30 Figure 23 shows that there is a strong inverse relationship between a customer's load factor and their residual charges (when normalised as $/MWh). Customers with a lower load factor will receive a higher residual charge in $/MWh terms. This is caused by the residual allocator which is a measure of peak capacity, and is modelled using the anytime maximum demand (or AMD). If a customer has a high peak demand, but relatively low offtake in energy terms (MWh), then they'll have a low load factor, and consequently higher residual charges.

Figure 23: Effect of customer load factor on residual charge



Heat maps

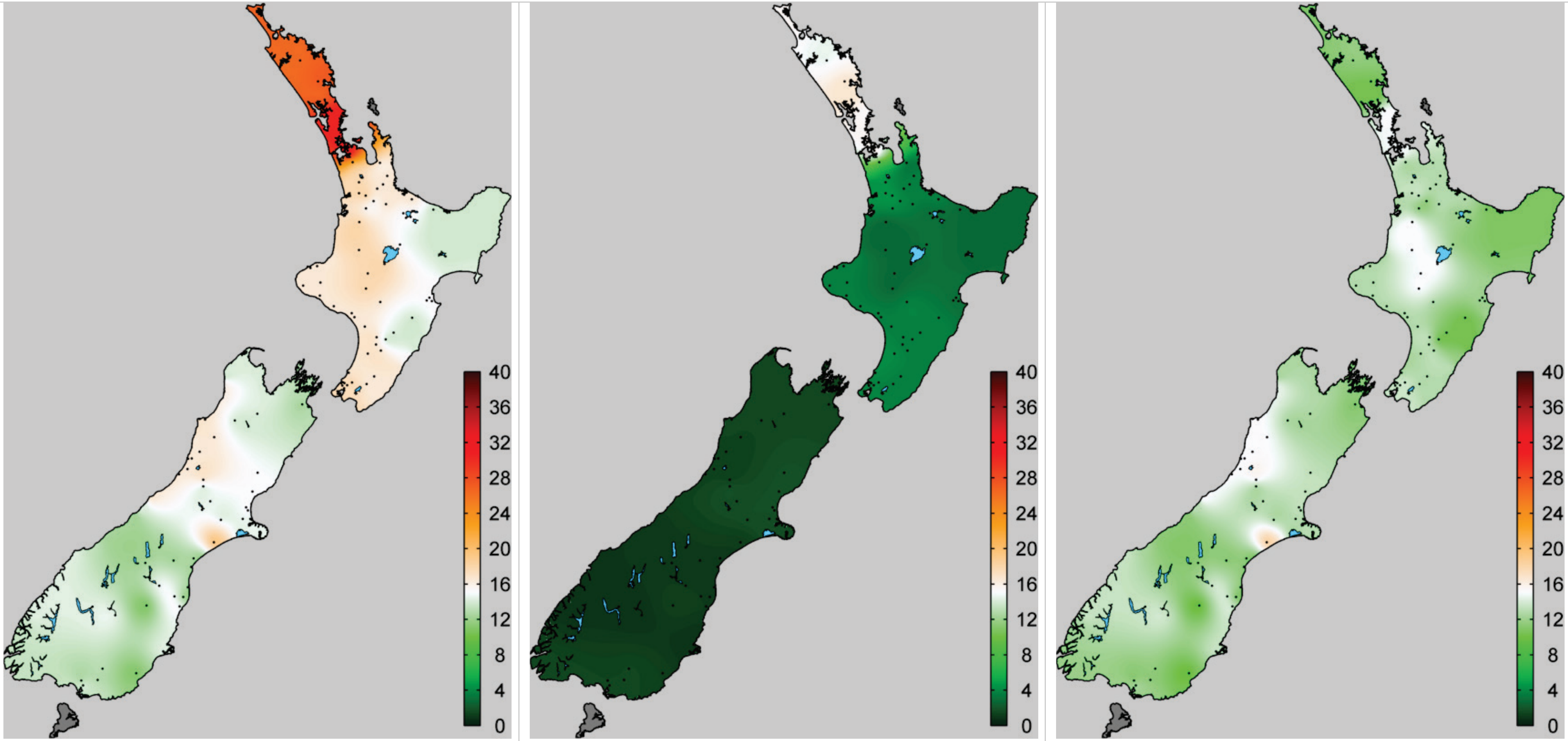
D.31 This section of the Appendix provides heat maps that show charging rates on load, in fully variabilised terms.

D.32 The charging rates shown are net of LCE.

D.33 Figure 24 shows charging rates, for each option and the status quo.

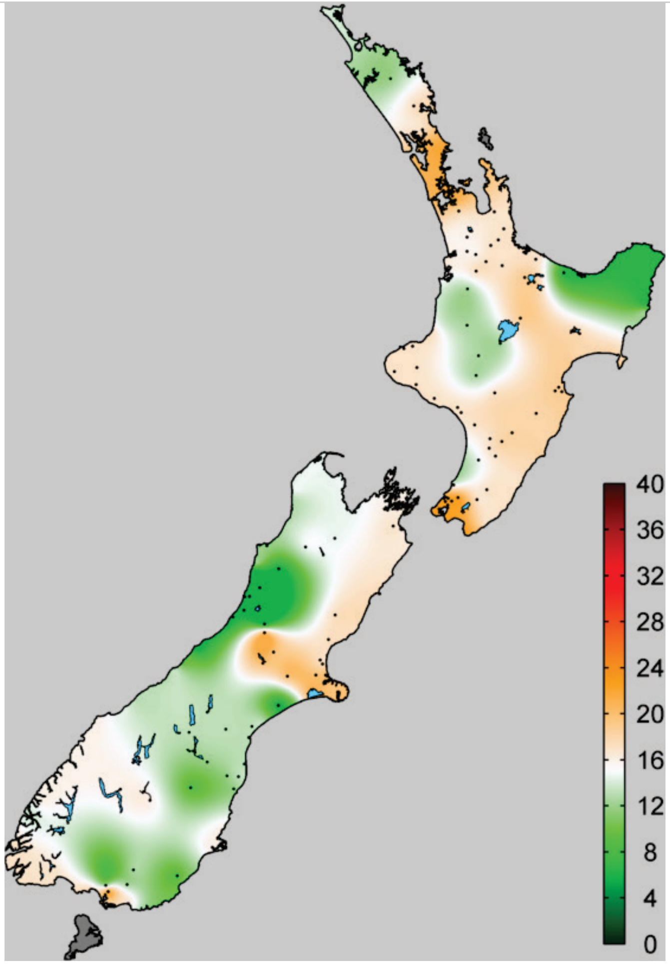
D.34 The heat maps in Figure 24 do not include uplift in energy prices as a result of generators passing on transmission charges they incur. It is assumed that, generators are unable to recover the transmission charges they face by raising the price of energy.

Figure 24: Modelled charging rates for offtake, in fully variabilised terms ($/MWh)

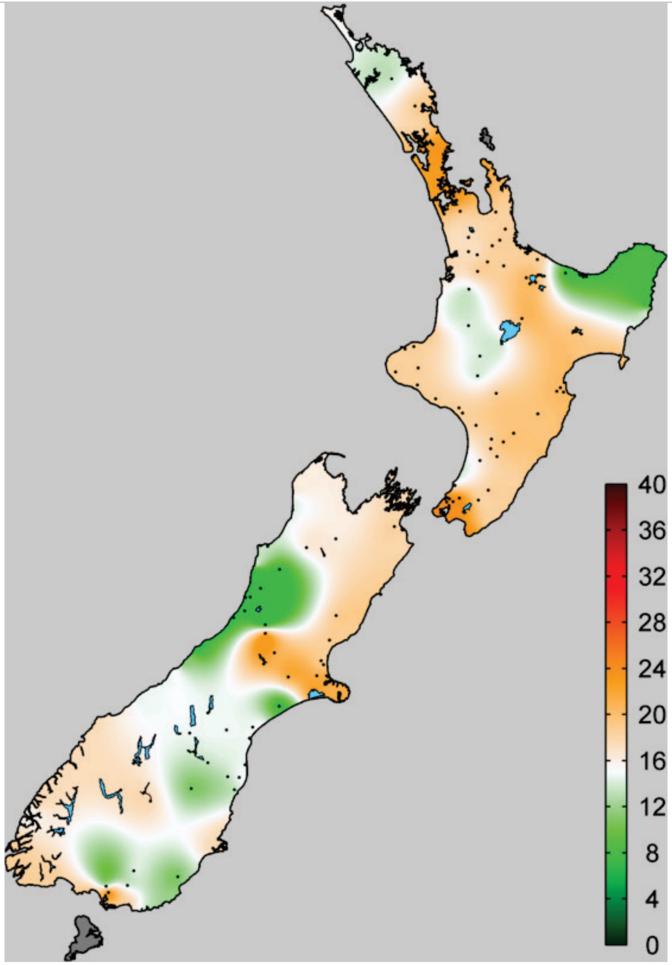


Area of Benefit and Residual charge – no generator pass-through	**Area of Benefit component only (residual excluded)** – no generator pass-through	**Residual component only (AoB excluded)** – no generator pass-through

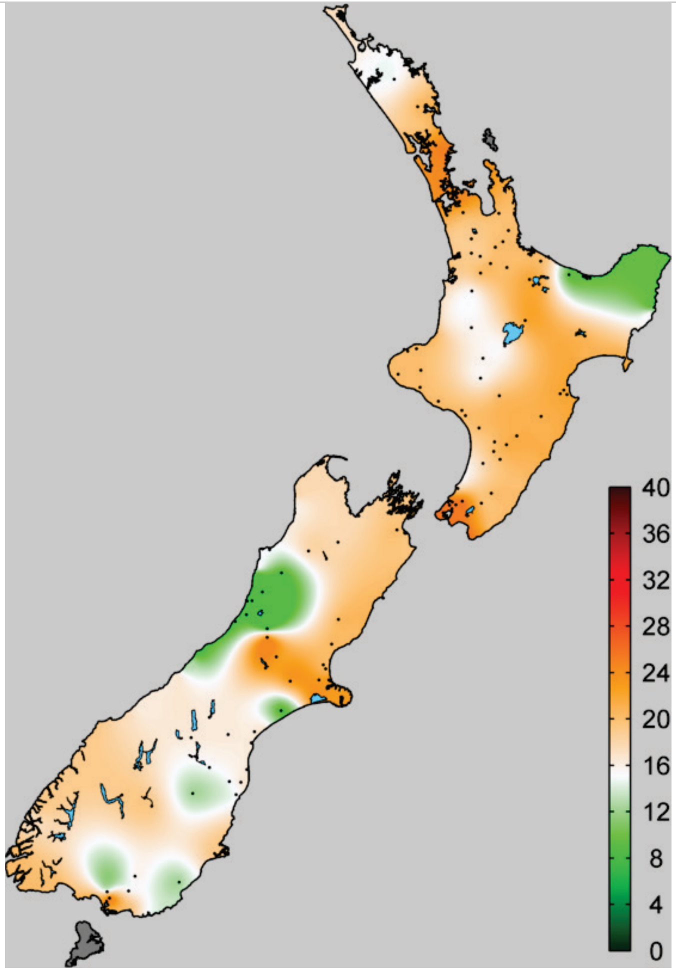
Status quo 2017 TPM in fully variabilised terms ($/MWh)



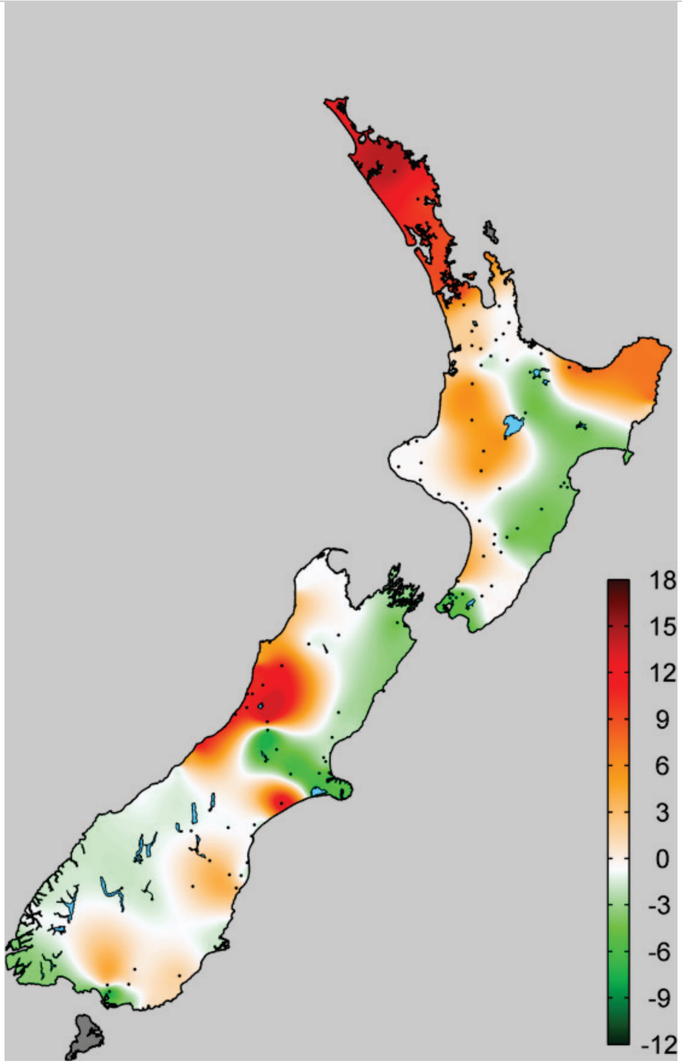
Status quo (as at 2017) –
no generator pass-through



Status quo (as at 2017) –
50% pass-through

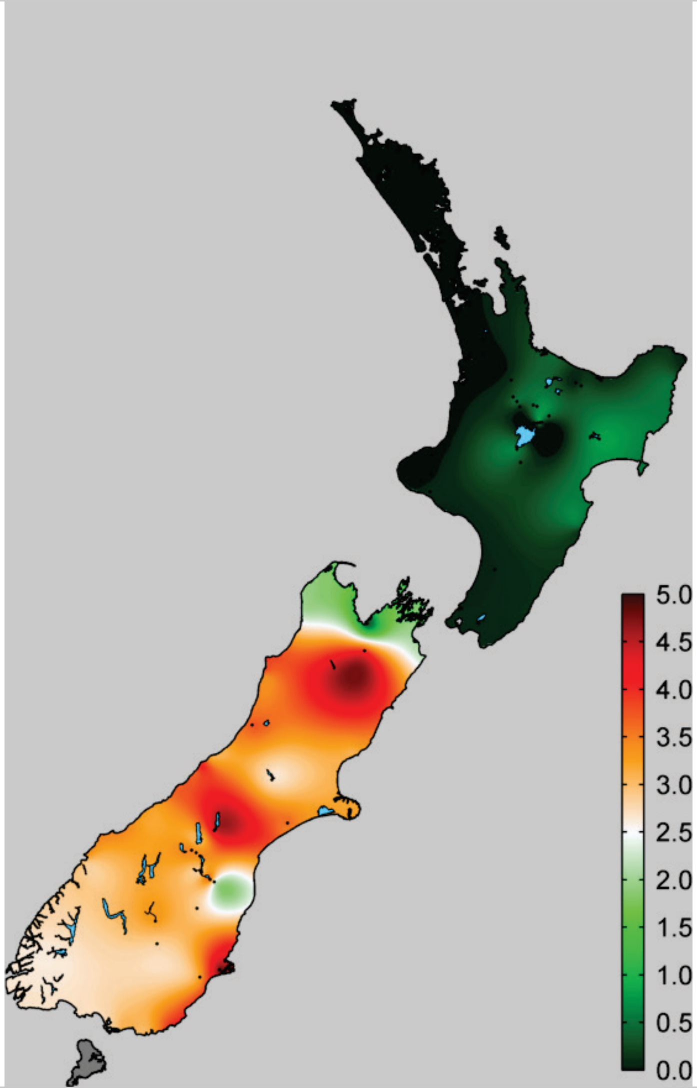


Status quo (as at 2017) –
100% pass-through



Difference between Area of Benefit plus Residual, and the Status Quo - no generator pass-through

Figure 25: Modelled charging rates for generation, in fully variabilised terms ($/MWh)



Area of Benefit charges for generation

Residential impacts

D.35 This section of the Appendix provides information on the modelled impacts of these options on typical residential households.

D.36 Note in relation to household bill increases:

(a) consumers, including residential consumers, that would pay higher charges have also gained greater benefits from recent major transmission investment (ie, reduced prices and improved reliability)

(b) the Authority's proposals would be expected to lead to more efficient investment, and hence to place downward pressure on costs faced by all parties in the mid- to long-term.

D.37 Key assumptions made in this section of the Appendix are that:

(a) all transmission charges on distributors would be passed on from distributors to retailers, and retailers to customers, on a per-MWh basis

(b) all customer classes in a given distributor area would face the same transmission charge in per-MWh terms

(c) typical residential tariffs (fully variabilised, excluding GST) have been sourced from MBIE's electricity price surveys

(d) a typical household would consume the following quantity of electricity:

Table 12: Typical household consumption (kWh per year) by distributor

Distributor	Household consumption (kWh per year)	Distributor	Household consumption (kWh per year)
Alpine Energy	8339	Northpower	6369
Aurora Energy	8233	Orion	8790
Buller Electricity	5481	OtagoNet JV	6982
Centralines	6956	Powerco	6371
Counties Power	7998	Scanpower	7110
Eastland Network	6319	The Lines Company	8033
Electra	6465	The Power Company	8517
Electricity Ashburton	8725	Top Energy	6065
Electricity Invercargill	8480	Unison	7101
Horizon	6322	Vector	7119
Lakeland Network[276]	9250	Waipa Power	7648
Mainpower	8887	WEL	7026
Marlborough Lines	7215	Wellington Electricity	7160
Network Tasman	6979	Westpower	6151
Network Waitaki	7577		

[276] This data has been estimated from Queenstown data.

D.38 Further:

(a) the figures show the impact with, and without, the ACOT payments that some distributors make to embedded generators. This is an estimate of ACOT only, and is based on Commerce Commission disclosure data. This data can include ACOT for other allowances than embedded generation. Further, some embedded generation may efficiently reduce peak network demands, so this ACOT information is only broadly indicative of the reduced costs of ACOT that may arise from the new TPM.

(b) connection, kVar and LRMC charges, and revenues recovered through LCE, are omitted

(c) pass-through of generation charges to load is not modelled.

D.39 On this basis:

(a) Table 13 shows residential impacts on a c/kWh basis

(b) Table 14 shows residential impacts as a percentage of the total retail tariff

(c) Table 15 shows residential impacts in ‘$ per household per year’ terms.

D.40 All three tables are expressed relative to the status quo.

Table 13: Modelled effect on prices faced by residential consumers, in c/kWh terms

	Proposal Minus Status Quo (assuming ACOT payments continue)	Proposal Minus Status Quo (assuming ACOT payments do not continue)
Alpine Energy	-0.08	-0.08
Aurora Energy	-0.17	-0.70
Buller Electricity	0.48	0.48
Centralines	-0.41	-0.41
Counties Power	0.41	0.41
Eastland Network	-0.38	-1.26
Electra	0.22	-0.10
Electricity Ashburton	1.34	1.17
Electricity Invercargill	-0.75	-0.75
Horizon	0.72	0.04
Lakeland Network	-0.36	-0.36
Mainpower	-0.22	-0.38
Marlborough Lines	-0.43	-0.47
Network Tasman	-0.06	-0.07
Network Waitaki	0.28	0.28
Northpower	1.00	0.56
Orion	-0.50	-0.54
OtagoNet JV	0.18	-0.06
Powerco	-0.04	-0.25
Scanpower	-0.39	-0.39
The Lines Company	0.52	0.05
The Power Company	0.05	-0.23
Top Energy	1.44	0.34
Unison	-0.35	-0.72
Vector	0.93	0.81
Waipa Power	-0.12	-0.12
WEL	0.19	-0.11
Wellington Electricity	-0.49	-0.50
Westpower	1.08	0.79

Figure 26: Difference between the proposal and the status quo (c/kWh)

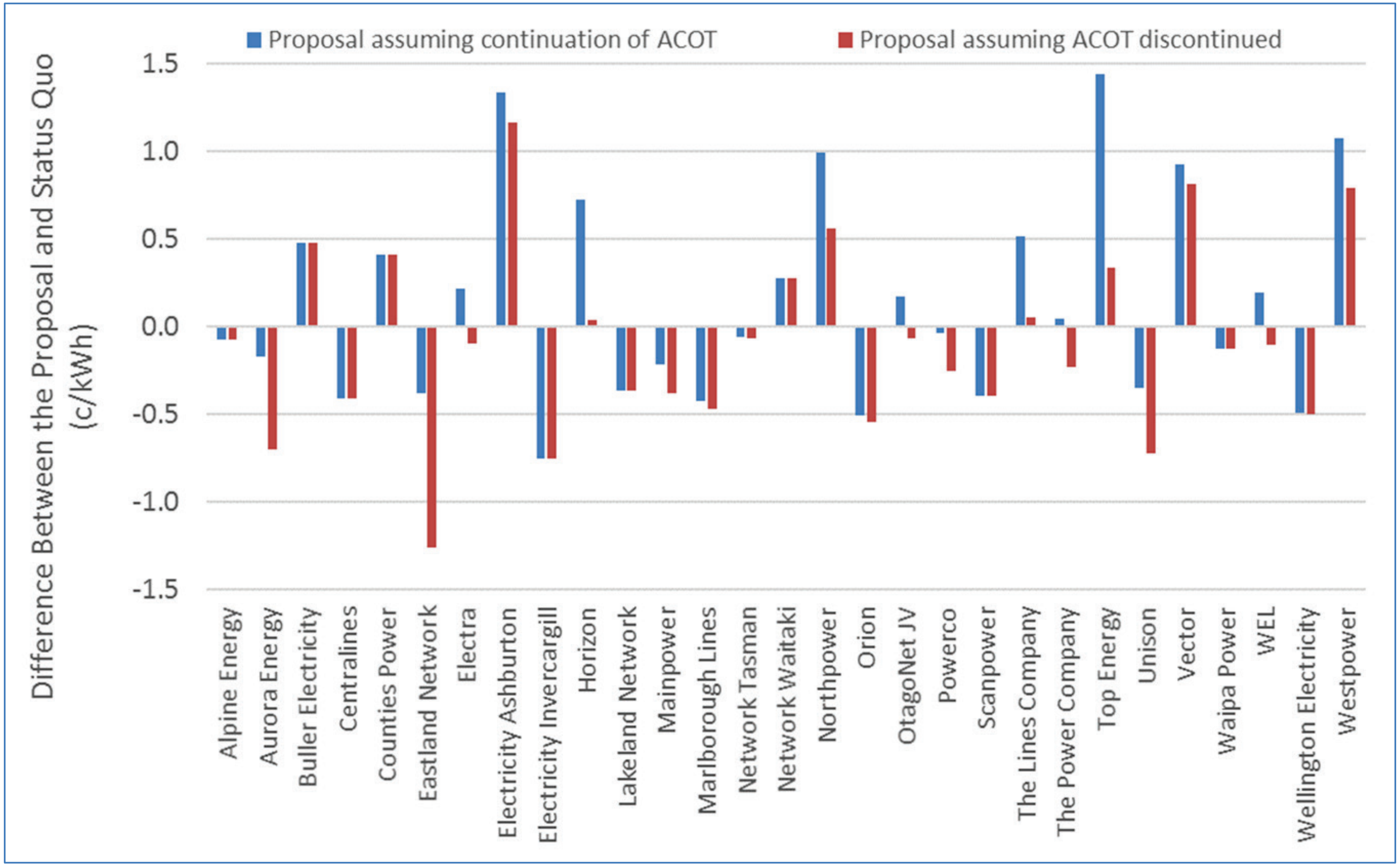


Table 14: Modelled effect on prices faced by residential consumers, as a percentage of the total retail tariff

	Proposal Minus Status Quo (assuming ACOT payments continue)	Proposal Minus Status Quo (assuming ACOT payments discontinue)
Alpine Energy	-0.3%	-0.3%
Aurora Energy	-0.7%	-2.9%
Buller Electricity	1.5%	1.5%
Centralines	-1.4%	-1.4%
Counties Power	1.7%	1.7%
Eastland Network	-1.4%	-4.5%
Electra	1.0%	-0.4%
Electricity Ashburton	5.8%	5.0%
Electricity Invercargill	-3.4%	-3.4%
Horizon	2.9%	0.2%
Lakeland Network	-1.5%	-1.5%
Mainpower	-0.9%	-1.6%
Marlborough Lines	-1.5%	-1.6%
Network Tasman	-0.2%	-0.3%
Network Waitaki	1.2%	1.2%
Northpower	4.0%	2.3%
Orion	-2.1%	-2.3%
OtagoNet JV	0.5%	-0.2%
Powerco	-0.1%	-0.9%
Scanpower	-1.6%	-1.6%
The Lines Company	1.9%	0.2%
The Power Company	0.2%	-0.9%
Top Energy	4.4%	1.0%
Unison	-1.3%	-2.7%
Vector	3.9%	3.4%
Waipa Power	-0.6%	-0.6%
WEL	0.8%	-0.4%
Wellington Electricity	-2.1%	-2.1%
Westpower	3.8%	2.7%

Figure 27: Difference between the proposal and the status quo (as a proportion of the retail tariff)

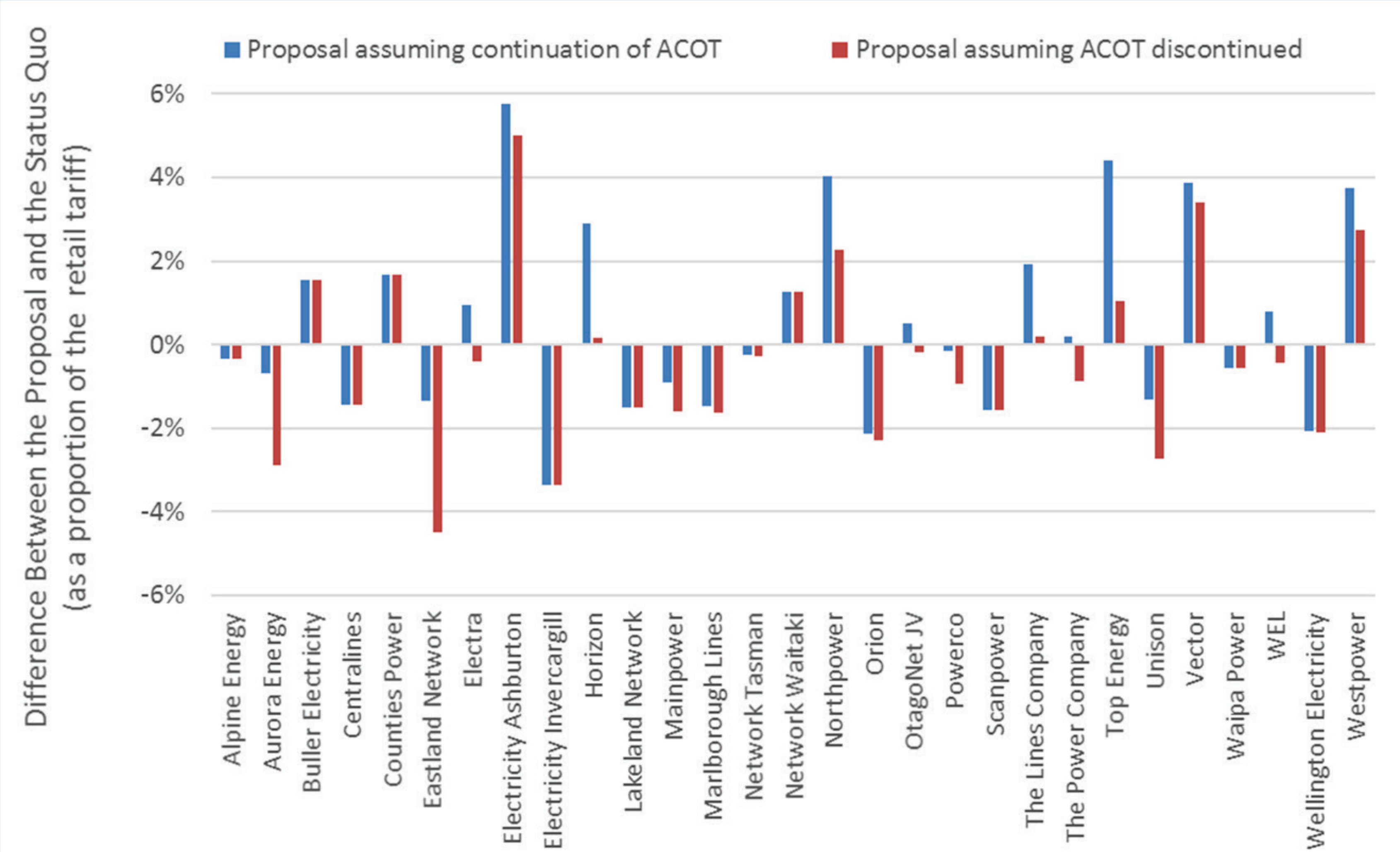


Table 15: Modelled effect on prices faced by residential consumers, in '$ per household per year' terms for a typical household

	Proposal Minus Status Quo (assuming ACOT payments continue)	Proposal Minus Status Quo (assuming ACOT payments discontinue)
Alpine Energy	-6	-6
Aurora Energy	-14	-57
Buller Electricity	26	26
Centralines	-29	-29
Counties Power	33	33
Eastland Network	-24	-79
Electra	14	-6
Electricity Ashburton	117	102
Electricity Invercargill	-64	-64
Horizon	46	3
Lakeland Network	-33	-33
Mainpower	-19	-34
Marlborough Lines	-31	-34
Network Tasman	-4	-5
Network Waitaki	21	21
Northpower	64	36
Orion	-44	-48
OtagoNet JV	12	-4
Powerco	-2	-16
Scanpower	-28	-28
The Lines Company	41	4
The Power Company	4	-20
Top Energy	87	21
Unison	-25	-51
Vector	66	58
Waipa Power	-10	-10
WEL	14	-7
Wellington Electricity	-35	-36
Westpower	66	49

Figure 28: Difference between the proposal and status quo as $/year for a typical household

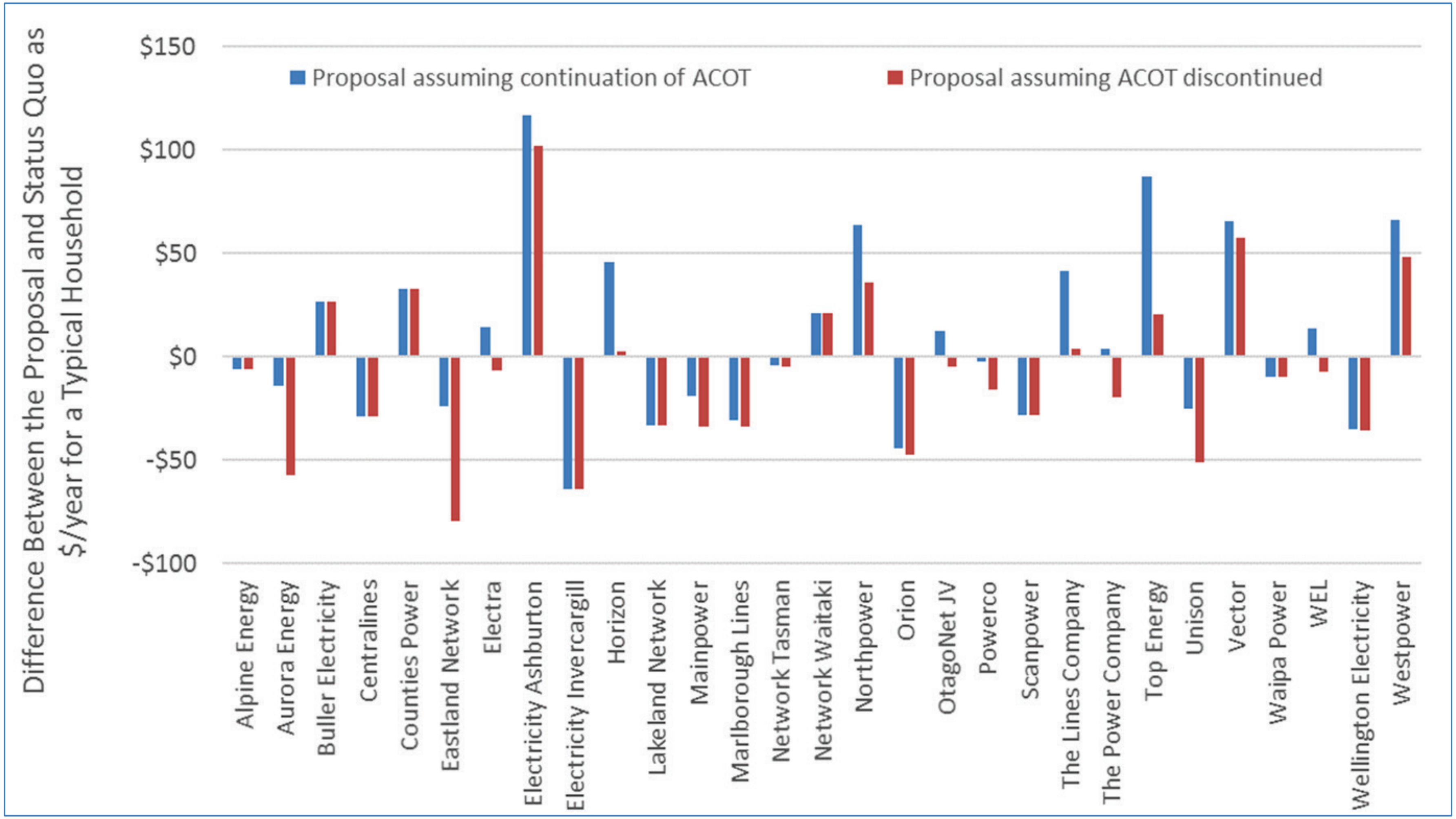
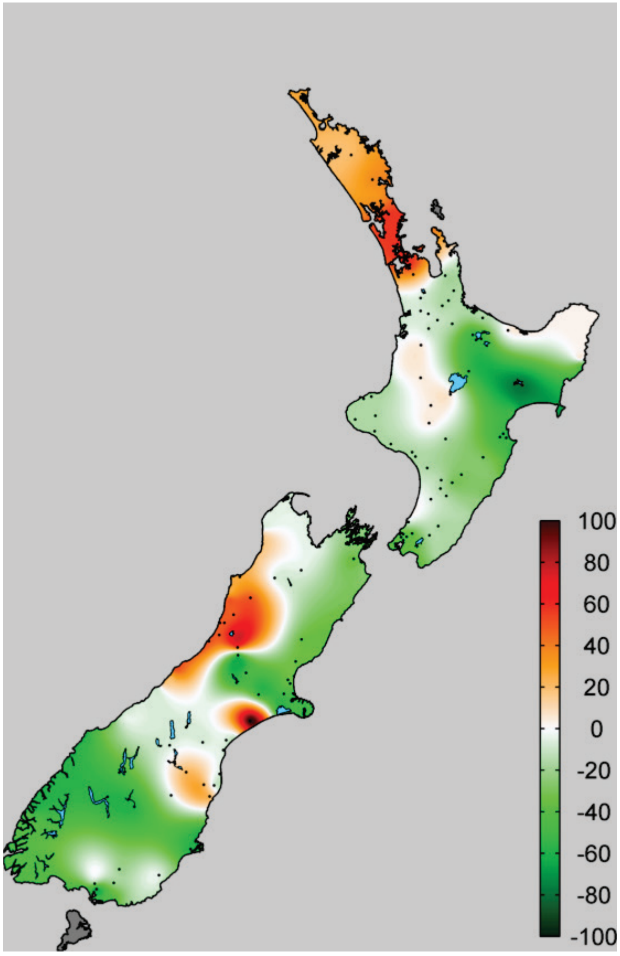


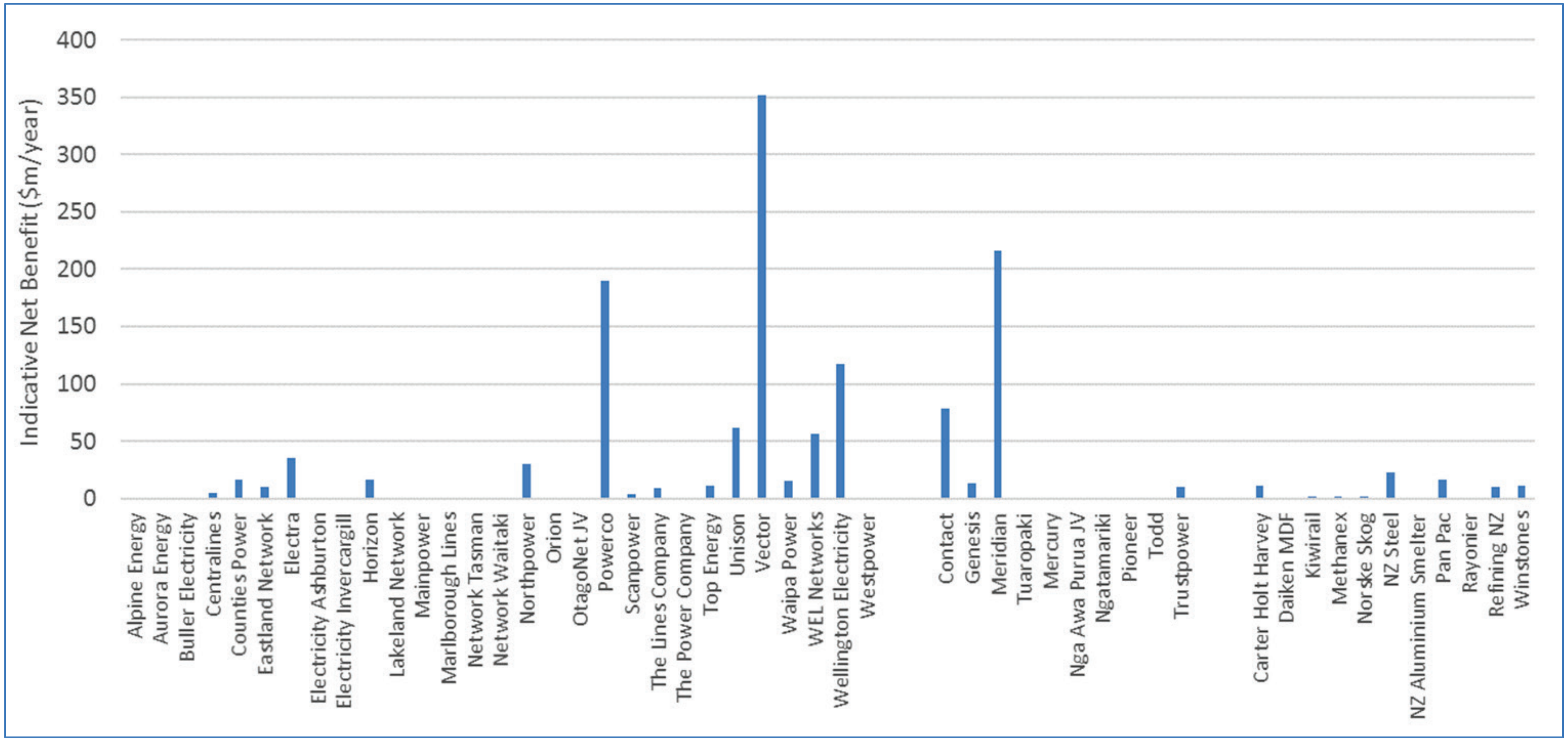
Figure 29: Difference between the proposal and status quo as $/year for a typical household (heat map) assuming ACOT payments discontinue



Indicative net benefits of the Pole 2 investment

D.41 The benefits from this investment accrue to North Island load and South Island generation. These benefits arise from avoiding constraints that would otherwise occur. South Island load and North Island generation get a net dis-benefit from the investment as they would be better off with a captive market of generation and load respectively. Their indicated net benefit is set to zero in the graph, because they would not be charged for this investment.

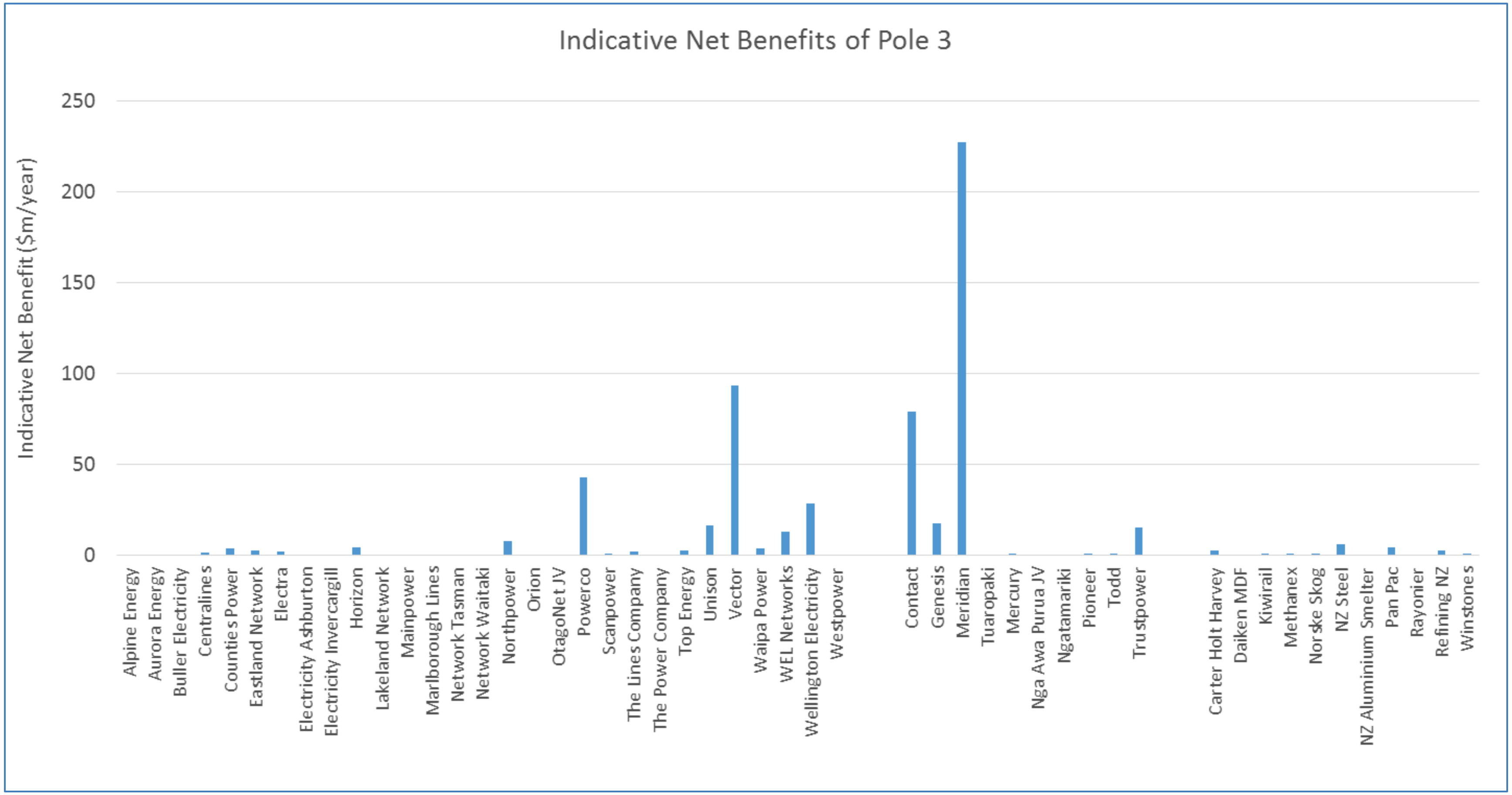
Figure 30: Indicative net benefits of the Pole 2 investment ($m/year)



Indicative net benefits of the Pole 3 investment

D.42 The benefits from this investment also accrue to North Island load and South Island generation. These benefits are similar to Pole 2 but are weighted more towards generation than to load. This arises because there are fewer periods of constraint compared to Pole 2. This means that while the generators get a similar benefit arising from ‘market access’, the benefits to load are a lot less (due to fewer constraints and thus not triggering the virtual generator or virtual demand response). Therefore, proportionately the generators get a greater allocation of charges for Pole 3 compared to Pole 2. South Island load and North Island generation get a net dis-benefit from the investment as they would be better off with a captive market of generation and load respectively. Their indicated net benefit is set to zero in the graph, because they would not be charged for this investment.

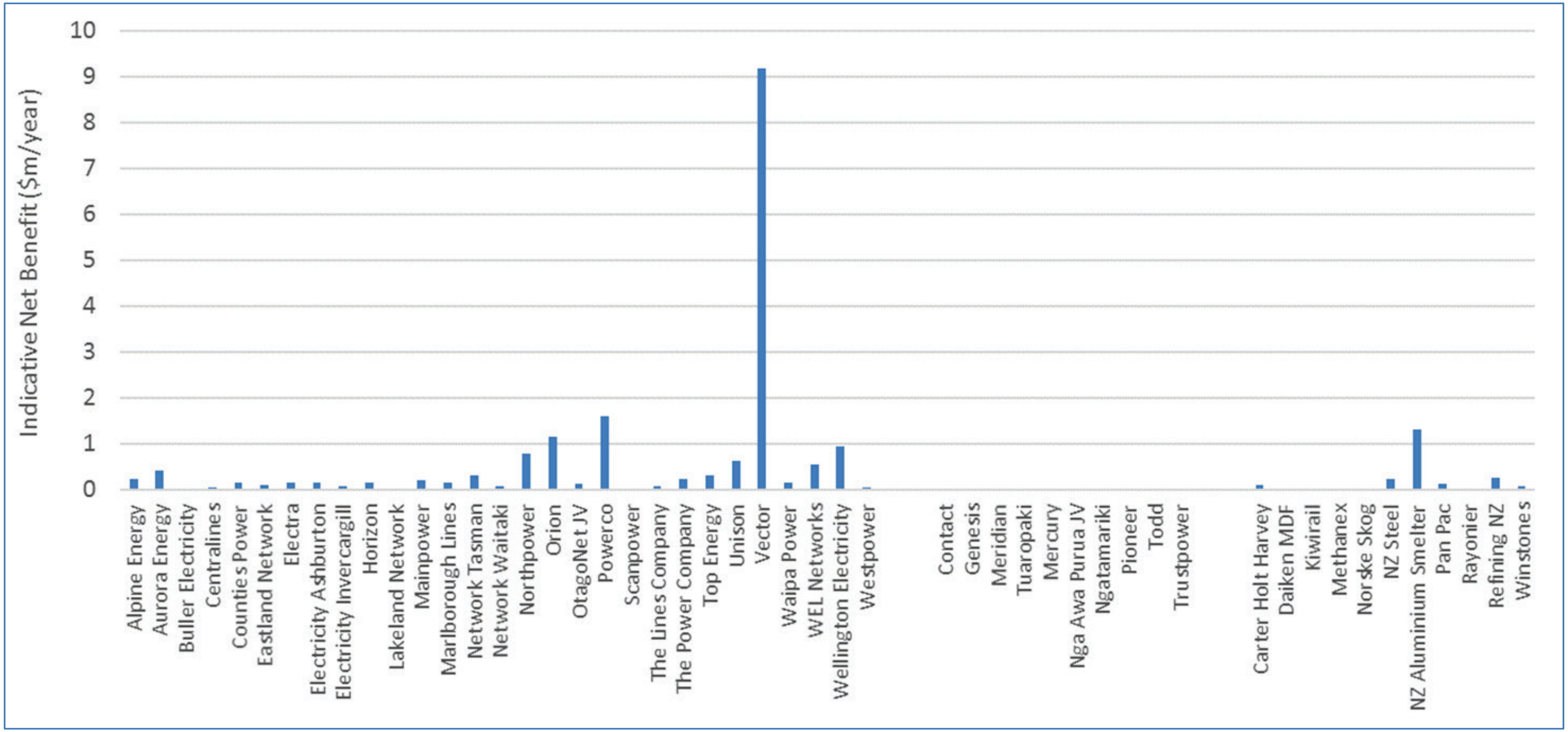
Figure 31: Indicative net benefits of the Pole 3 investment ($m/year)



Indicative net benefits of the North Auckland and Northland investment

D.43 The benefit of this investment are mainly related to reduced losses. Vector, Northpower and Top Energy get the largest losses benefit being downstream of the investment. However, all load receives a benefit arising from slightly lower marginal generation costs (ie, due to lower losses). Bigger loads (eg, NZ Aluminium Smelters) get larger benefits from the nationwide reduction in prices. The dis-benefits suffered by any party are not shown for the reason specified in paragraph D.41.

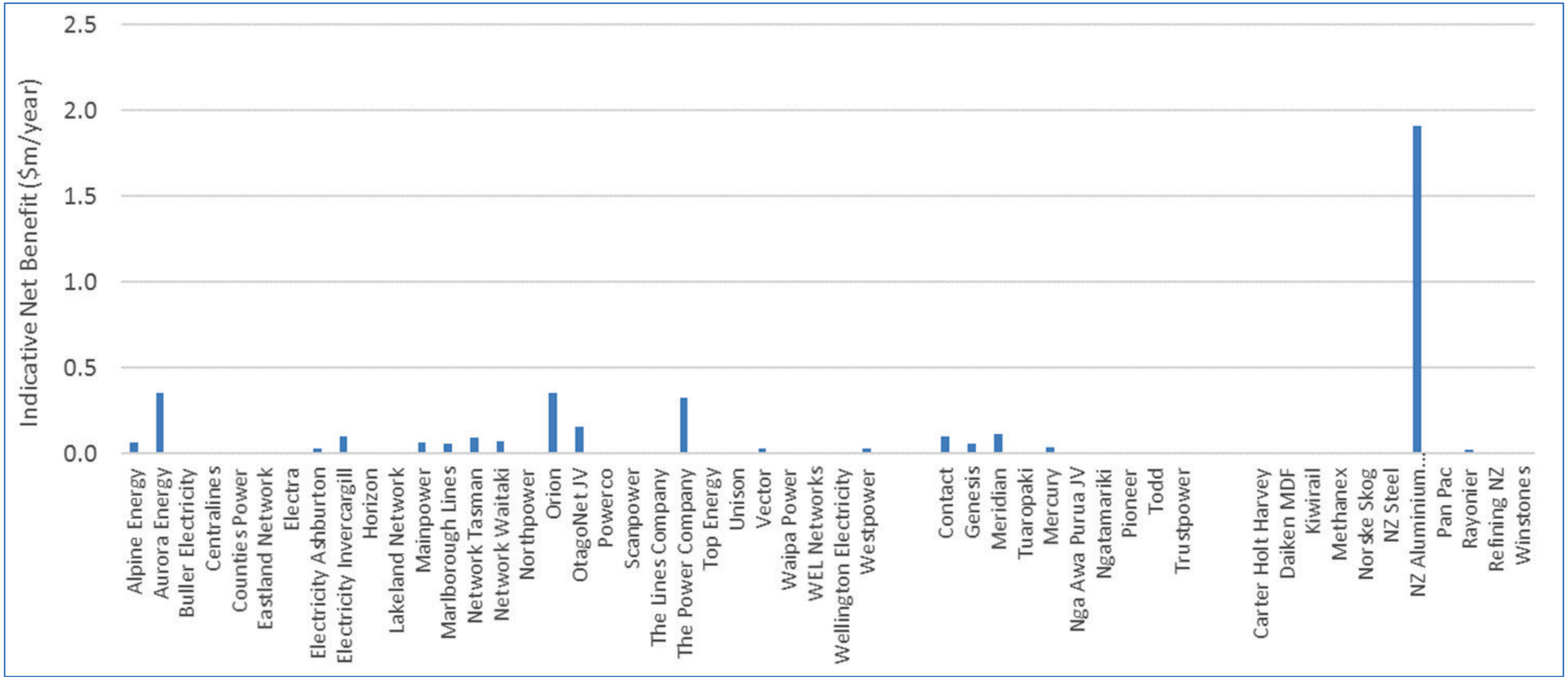
Figure 32: Indicative net benefits of the North Auckland and Northland investment ($m/year)



Indicative net benefits of the Lower South Island Renewables investment

D.44 The benefits arising from this investment are primarily due to a reduction in losses. Large loads close to the investment receive the biggest benefit. The dis-benefits suffered by any party are not shown for the reason specified in paragraph D.41.

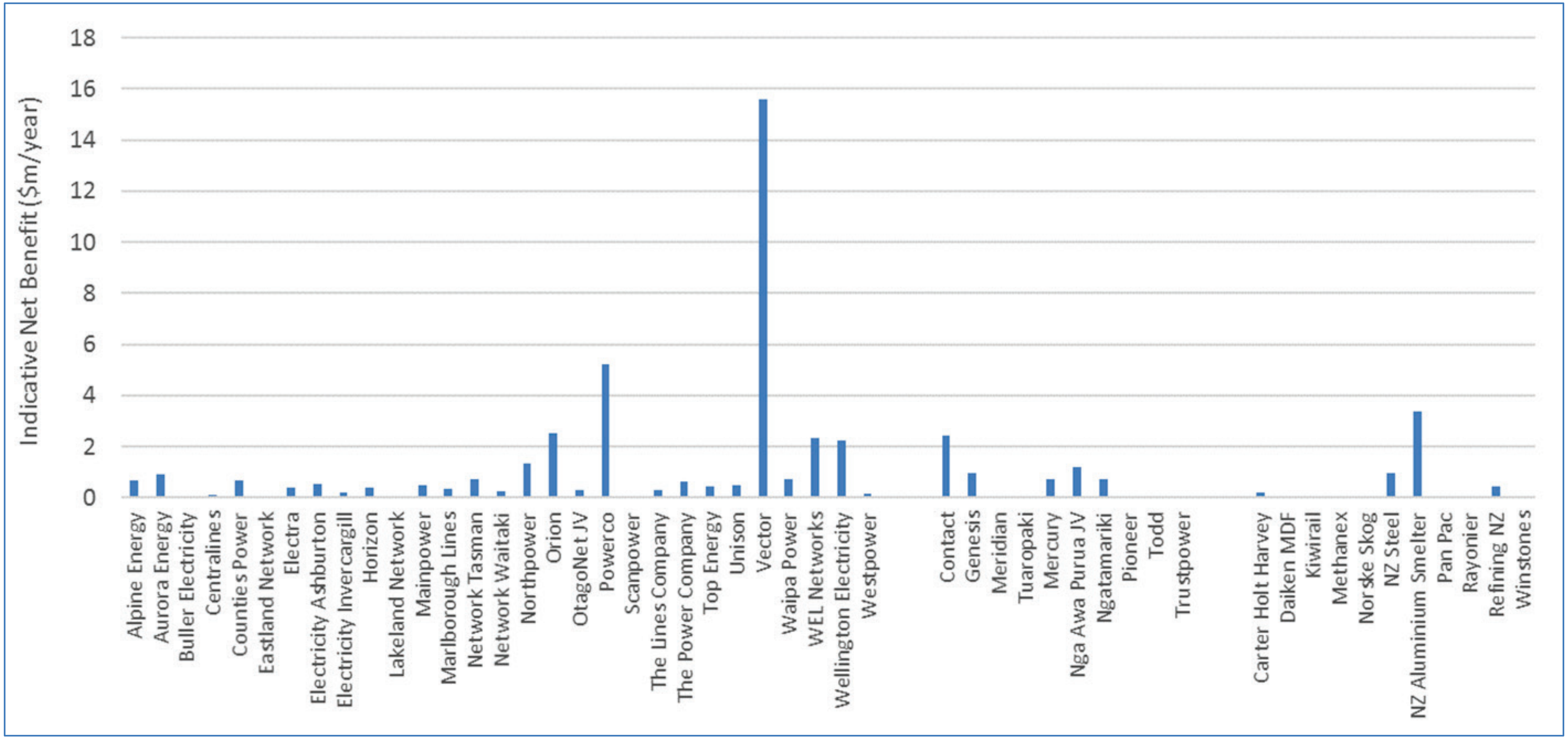
Figure 33: Indicative net benefits of the Lower South Island Renewables investment ($m/year)



Indicative net benefits of the Wairakei Ring investment

D.45 This investment has a predominantly losses based benefit, as there are only a small number of periods of constraint. Central North Island generation picks up a material benefit from this investment, as does all load (mainly due to lower losses) except Pan Pac and Eastland Network. Pan Pac and Eastland Network would be better off without the investment as they would have a captive market of generation, which would lower the average wholesale price in their region. The dis-benefits suffered by any party are not shown for the reason specified in paragraph D.41.

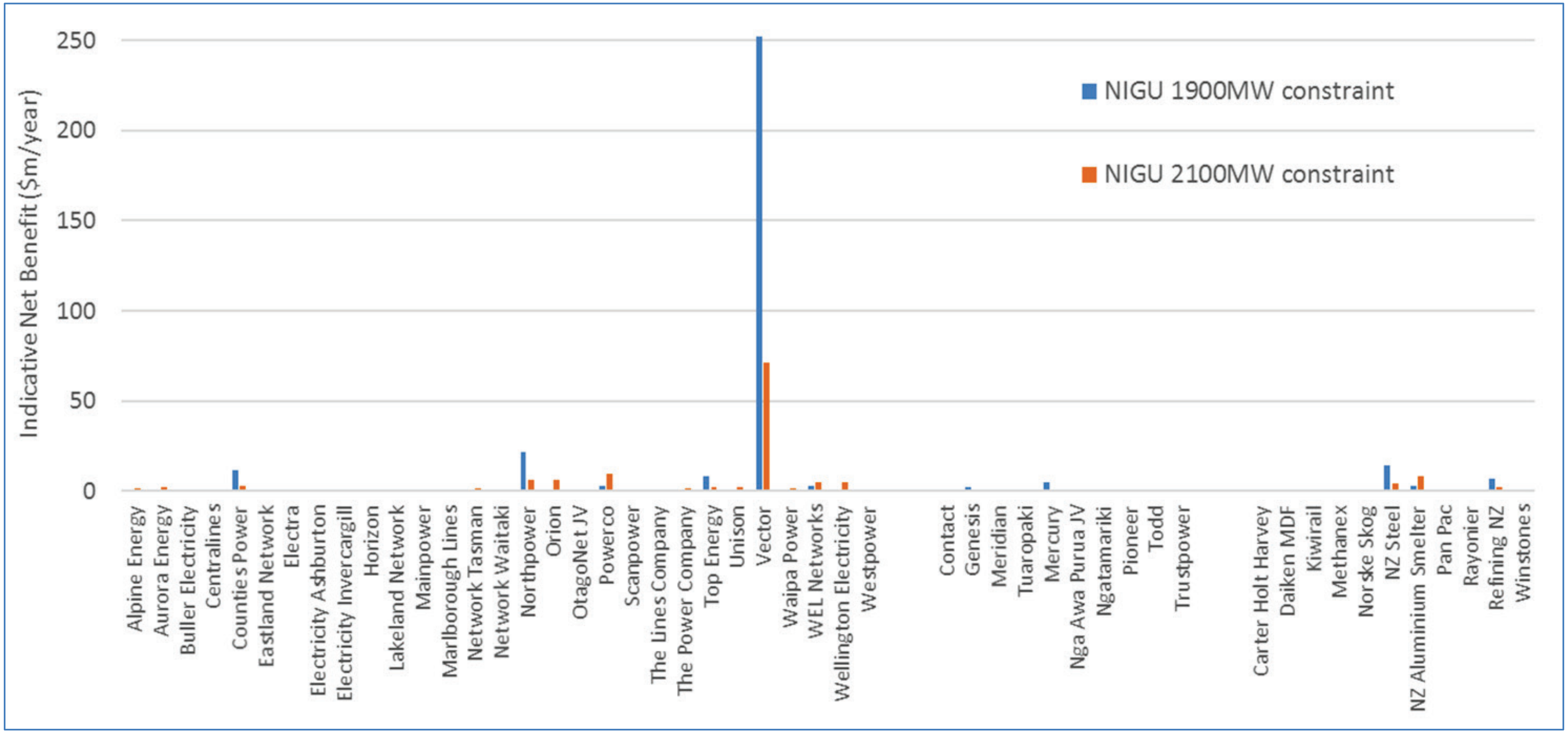
Figure 34: Indicative net benefits of the Wairakei Ring investment ($m/year)



Indicative net benefits of the North Island Grid Upgrade

D.46 This graph shows the effect of changing from a lower constraint value of 1900MW, to a higher constraint value of 2100MW. This shows the sensitivity of charges (in magnitude and distribution) to the constraint. The dis-benefits suffered by any party are not shown for the reason specified in paragraph D.41.

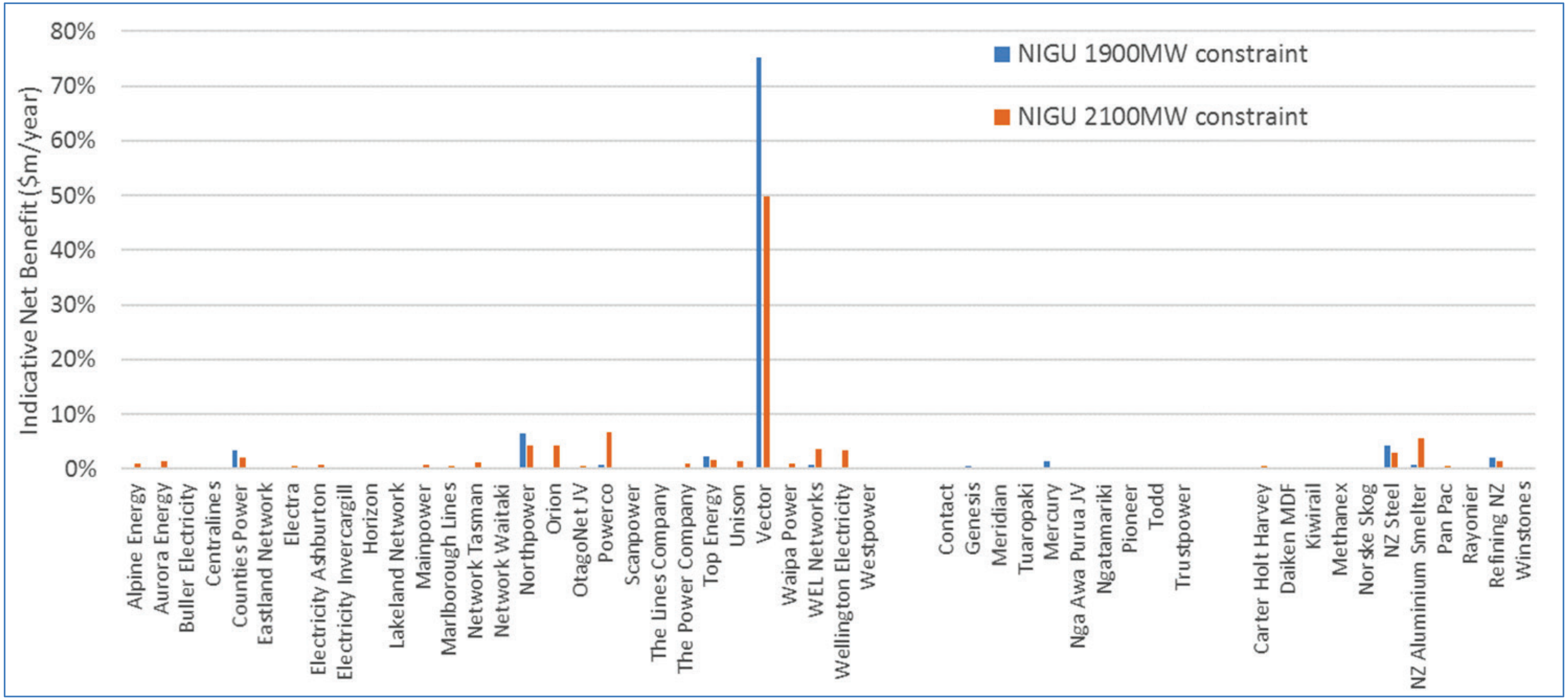
Figure 35: Indicative net benefits of the North Island Grid Upgrade ($m/year)



Indicative net benefits of the North Island Grid Upgrade investment (as a proportion of total indicative benefit)

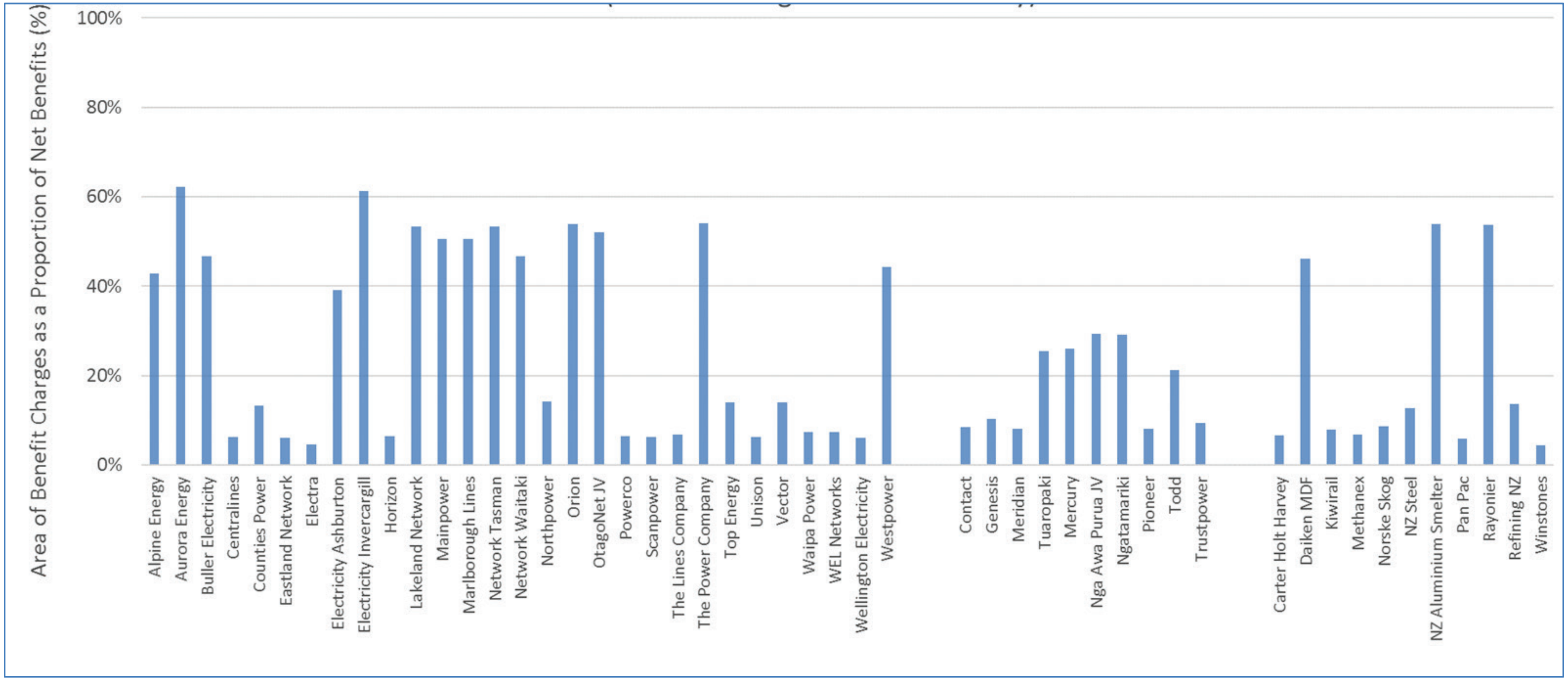
D.47 This graph shows the effect of changing from a lower constraint value of 1900MW, to a higher constraint value of 2100MW. This shows the sensitivity of charges (in magnitude and distribution) to the constraint, eg, Vector's share of the charges moves from 75% to 50%, and NZAS from below 1% to nearly 6%. The dis-benefits suffered by any party are not shown for the reason specified in paragraph D.41.

Figure 36: Customer net benefits as a proportion of total net benefit for NIGU ($m/year)



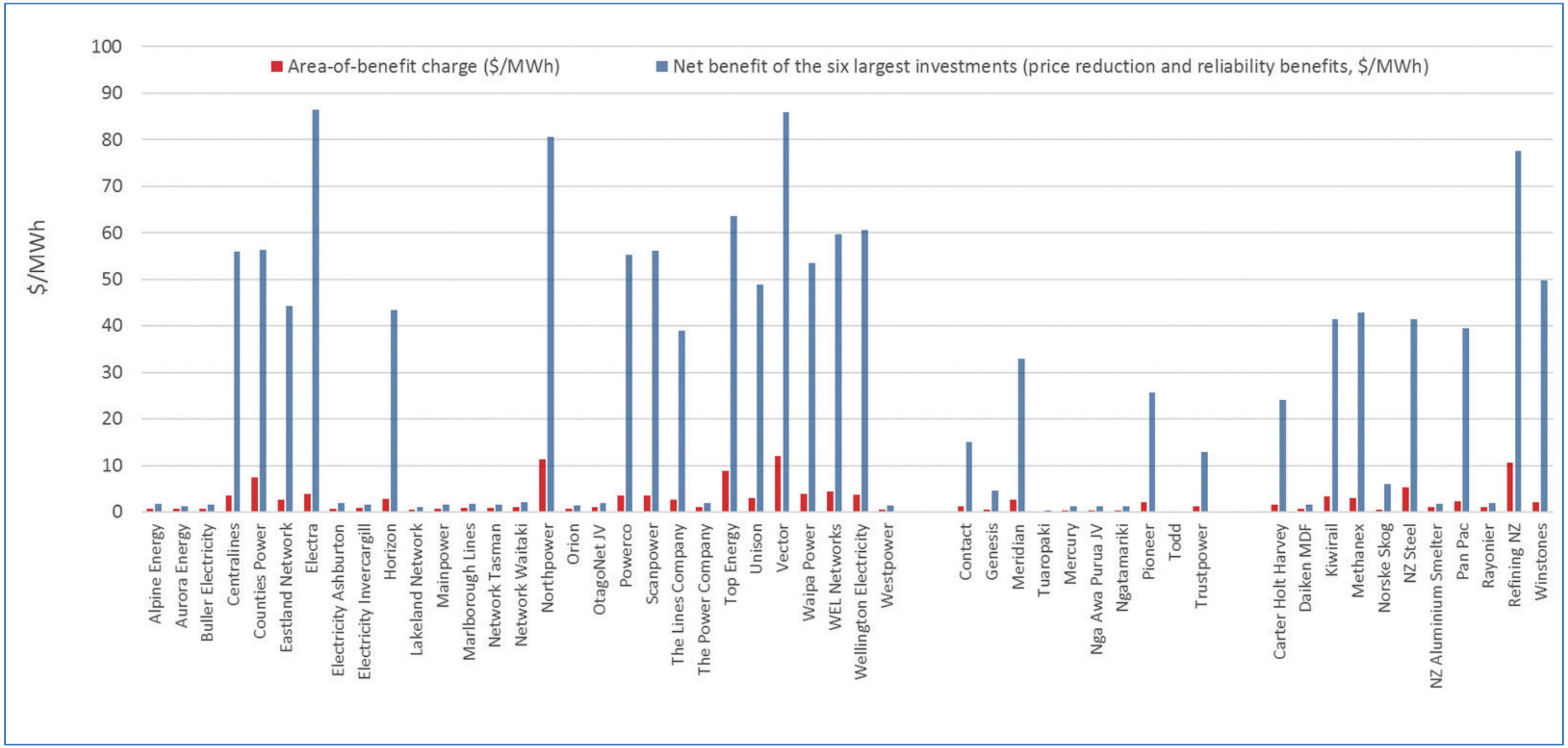
Customer charges under the proposal as a proportion of indicative net benefit (for the six large investments only)

Figure 37: Area-of-benefit charge as a proportion of net benefits, for the six large investments only (%)



Area of benefit charges compared to net benefits of the six largest investments

Figure 38: Area-of-benefit charge compared to indicative net benefits for the six largest investments (as $/MWh)



Appendix E Deeper connection option considered by the Authority

Introduction

E.1 This section describes in detail the design of the deeper connection charge considered by the Authority as part of the deeper connection option assessed in the cost-benefit analysis discussed in chapter 8 and in the evaluation of alternatives in chapter 9.

E.2 This section first describes how the deeper connection charge under the option considered would have been calculated, and then discusses the Authority's reasons for each element of the charge.

Calculation of the deeper connection charge

E.3 At a high level, the deeper connection charge for an asset would be calculated by:

(a) calculating a Herfindahl Hirschman Index (**HHI**) based on electricity flows through the asset to regions of electrically related nodes supplied through the asset (**load HHI**)

(b) calculating an HHI based on electricity flows through the asset from regions of electrically related nodes that supply through the asset (**generation HHI**)

(c) using the HHIs to determine the total deeper connection charge (if any) to be allocated to load and generation, for the asset. The deeper connection charge would not apply in relation to connection assets (ie assets for which revenue would be recovered through the connection charge)

(d) allocating the deeper connection charge for the asset to transmission customers, based on shares of physical capacity or flows (for load) or shares of flows (for generation).

E.4 Each of the above steps is described further below.

Load HHI and generation HHI calculated for the asset

E.5 Under the deeper connection charge, Transpower would calculate a load HHI and a generation HHI for the asset, based on electricity flows.

E.6 HHI is a measure of concentration. In the context of transmission assets, an HHI is calculated by squaring each percentage flow share, and then adding the resulting values to produce the HHI. A higher HHI means that there is a greater concentration of flows.[277]

E.7 A load HHI for the asset would be calculated based on the flows through the asset to regions of electrically related nodes supplied by the asset.

E.8 If the Authority had proposed the deeper connection charge, Transpower would have determined what these regions are in its development of the TPM. Transpower's planning regions may have been appropriate for this purpose.

[277] For more information about HHI, see the options working paper.

E.9 For example, if power is flowing through the asset to three different regions of electrically related nodes, with flow shares of 80%, 10%, and 10% respectively, the load HHI for the asset would be 6600, as shown in table 16 below:

Table 16: Example of calculation of load HHI

Region of electrically related nodes	Share of flow through the asset to the region	Squared flow
Region 1	80%	6,400
Region 2	10%	100
Region 3	10%	100
	Load HHI	**6,600**

E.10 A generation HHI would be calculated for each asset, based on the flows through the asset from regions of electrically related nodes. For example, if power is flowing through the asset from regions 4, 5 and 6, with flow shares of 40%, 30% and 30% respectively, the generation HHI would be 3,400, as shown in table 17 below:

Table 17: Example of calculation of generation HHI

Region of electrically related nodes	Share of flow through the asset from the region	Squared share
Region 4	40%	1,600
Region 5	30%	900
Region 6	30%	900
	Generation HHI	**3,400**

E.11 In the example above, the flows through the asset to load parties are more concentrated than flows through the asset from generation parties.

HHI used to determine total charge to load and generation

E.12 Under the charge, Transpower would use the load HHI and generation HHI to determine the total deeper connection charge (if any) allocated to load and generation, for an asset.

E.13 To do this, Transpower would first determine a load variable and generation variable for the asset.[278]

[278] In the options working paper this was referred to as the “graduated cutoff”.

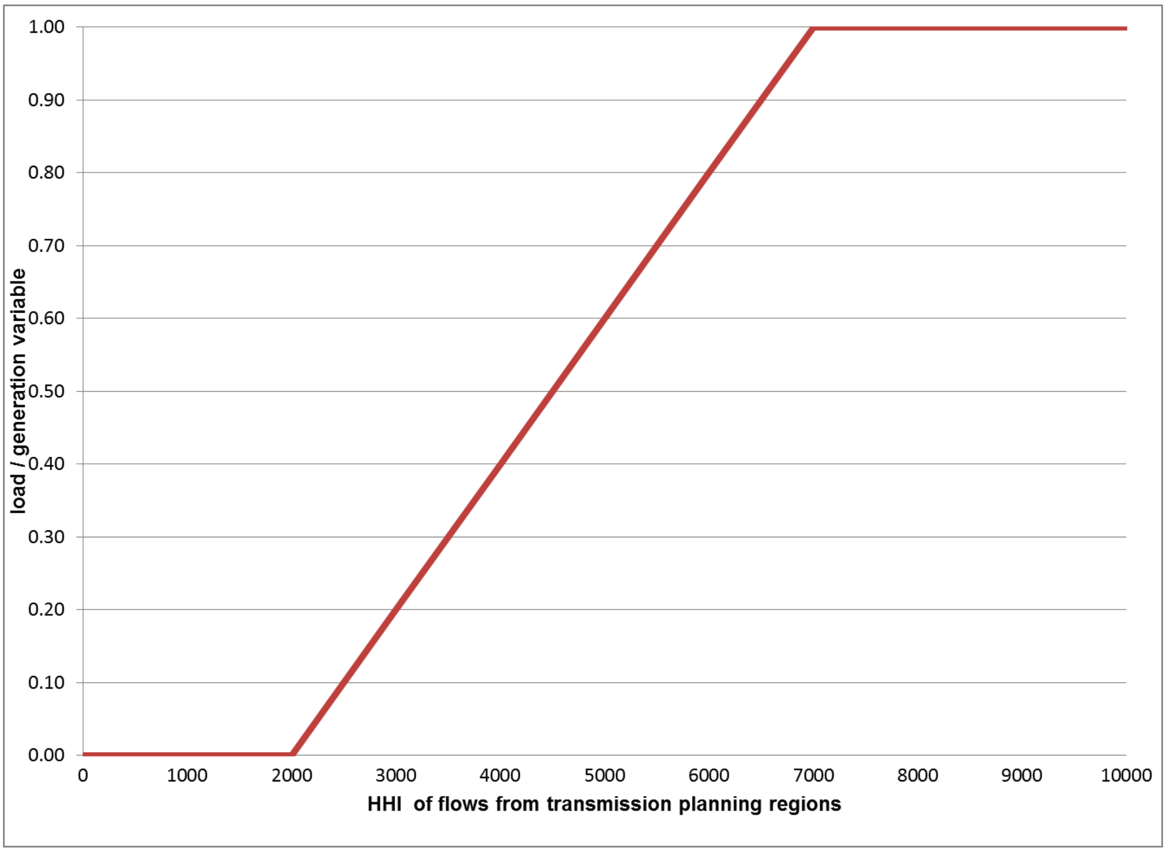
E.14 As illustrated in Figure 39 below, the load variable and generation variable depend on the relevant HHIs. The variable:

(a) is 0 if the HHI is 2,000 or less

(b) increases linearly from 0 at HHI=2,000 to 1 at HHI=7,000

(c) is 1 if the HHI is 7,000 or more.

Figure 39: Illustration of load variable



E.15 For example, the asset in the previous example has:

(a) a load HHI of 6,600, and hence the variable for load is .92 ((6,600 – 2,000) / 5,000)

(b) a generation HHI of 3,400, and hence the variable for generation is .28 ((3,400 – 2,000) / 5,000).

E.16 The load variable and the generation variable for an asset are used to determine the total deeper connection charge (if any) allocated to load and generation, for the asset.

E.17 The formula for this is:

(a) for load customers, variable_L / max(1, variable_L + variable_G)

(b) for generation customers, variable_G / max(1, variable_L + variable_G)

E.18 Applying that formula in the example above:

(a) Load customers would pay (.92 / (.92 + .28)) = .77 (or 77% of the cost of the asset through the deeper connection charge).

(b) Generation customers would pay (.28 / (.92 + .28)) = .23 (or 23% of the cost of the asset through the deeper connection charge).

E.19 It follows that the cost of an asset is:

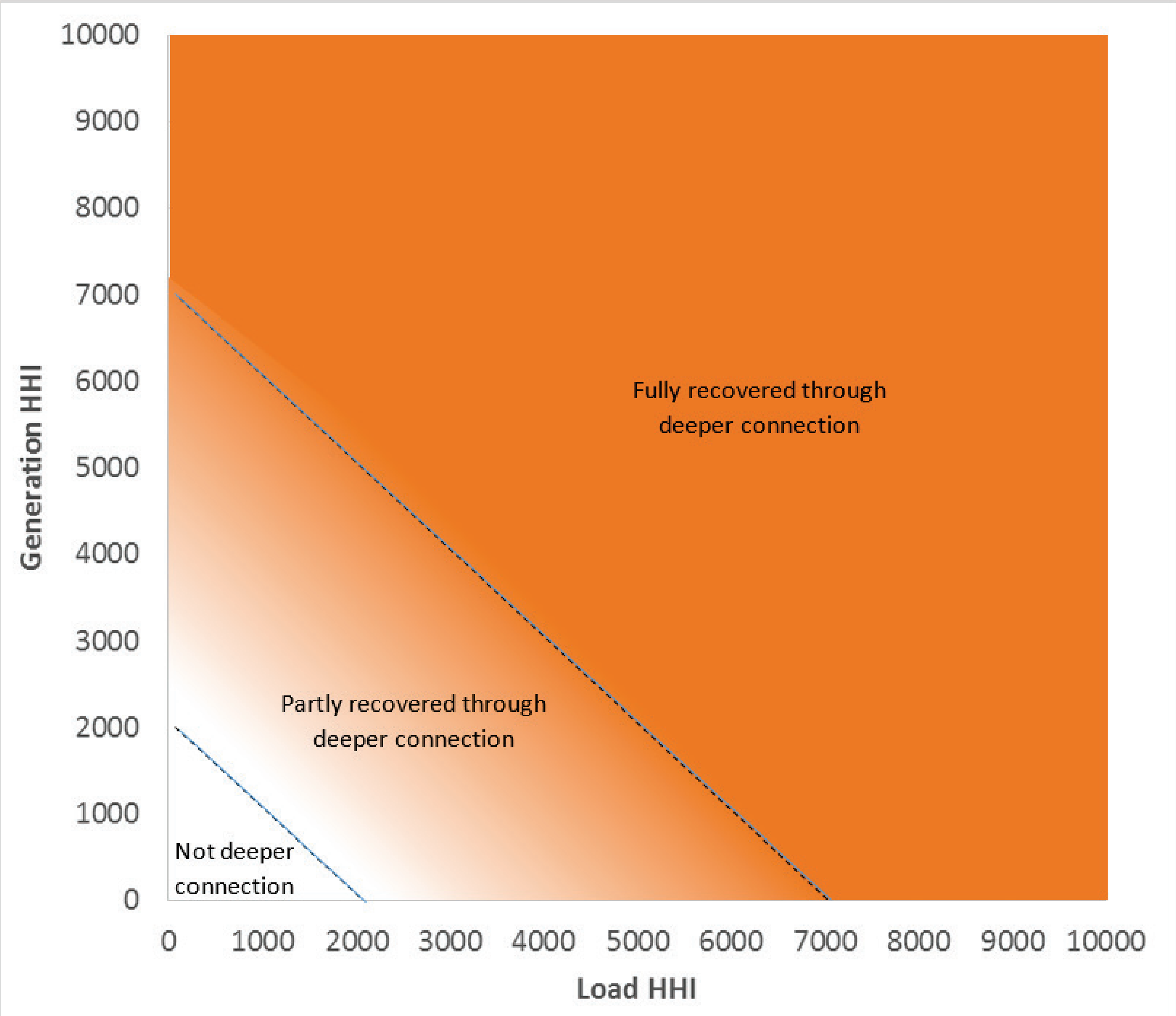
(a) not allocated through the deeper connection charge, if the load variable and the generation variable are both 0. This would only be the case if the load HHI and the generation HHI for the asset are both less than 2,000

(b) partially recovered through the deeper connection charge, if the sum of the load variable and the generation variable is greater than 0 but less than 1

E.20 fully allocated through the deeper connection charge, if the sum of the load variable and the generation variable is 1 or more.

E.21 This is illustrated in figure 40 below:

Figure 40: Illustration of cost recovery under deeper connection



Allocation to customers of deeper connection charge for the asset

E.22 Having determined the total deeper connection charge to load and generation for the asset, the charge is allocated to transmission customers that have load or generation that flows through the assets.

E.23 For load customers, the deeper connection charge would be allocated based on shares of the physical capacity of the relevant load at nodes with flows through the asset. If charges to generation are allocated on the basis of flows and both generation and load use the asset, charges would be pre-allocated to load and generation according to flows, and then allocated to load according to physical capacity. A graduated de minimis would be applied so that:

(a) load with flows from nodes through the asset of less than 1% of the node’s physical capacity would not pay the charge in relation to the asset

(b) load with flows from nodes through the asset of more than 5% of the node’s physical capacity would pay 100% of the charge in relation to the asset

(c) load flows from nodes between 1% and 5% of the nodes’ physical capacity would pay a proportion of the charge increasing linearly from 0% for flows of 1% to 100% for flows of 5%.

E.24 Under the charge, Transpower would specify a method for determining the physical capacity of a load customer in its development of the TPM.

E.25 For generation, the deeper connection charge would be allocated based on shares of flows.

Charge based on depreciated historical cost, replacement cost or optimised replacement cost

E.26 The deeper connection charge would:

(a) for assets commissioned before the date of the guidelines, be based on depreciated historical cost (**DHC**) and potentially optimised[279]

(b) for an asset commissioned after the date of the guidelines the Authority's current preferred option is that the charge would be based onreplacement cost (**RC**), however the Authority does not have a firm view on adopting this approach.[280] The charge would potentially be optimised after the asset has been commissioned for a period of time specified in the TPM, eg, 10 years.

E.27 Transpower would determine the optimised costs for assets in accordance with a method required to be set out in the TPM having been determined by Transpower in its development of the TPM. A party would be able to request that the value of an asset be optimised, even if the asset's value has been optimised previously.

Other elements of the charge

E.28 The deeper connection charge would apply to existing and new assets.

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[279] Refer to chapter 7 for a discussion on how optimisation would be applied.

[280] This is consistent with the Authority’s proposed area-of-benefit charge. Refer chapter 7.

E.29 The deeper connection charge would be recalculated annually, based on a 5 year rolling average.

E.30 The TPM would specify how flow tracing would be applied to substations.

Authority's reasons for including each element of the deeper connection charge

Charge allocated to load and generation

E.31 As described above, the deeper connection charge would be allocated to both load customers and generation customers. Decisions by both load customers and generation customers affect the need for transmission investment. Both load customers and generation customers should therefore face the deeper connection charge to encourage them to take into account the transmission investment implications of their own demand for transmission services and investment decisions, as this will promote efficient investment overall.

E.32 This is because both load customers and generation customers use and benefit from access to the grid, and the deeper connection charge identifies which load customers and generation customers most use each asset. The Authority notes the views of some submitters that allocating the deeper connection charge to generation would not reflect benefits. The Authority is of the view that having access benefits both load customers and generation customers. It benefits load customers by giving them access to electricity, and it benefits generation customers by providing a more extensive market for their product.

E.33 Some submitters raised concerns that allocating the deeper connection charge to generation customers would not reflect benefits, and could result in inefficient outcomes.[281] The Authority accepts that the deeper connection charge may not always reflect benefits for both generation customers and load customers subject to the charge. The deeper connection charge applies a charge according to transmission flows, or use, which may or may not be related to the benefit a party receives from the asset.

E.34 To help reduce the risks of inefficient outcomes from this, the Authority has explored changes to the design of the charge so that it would only fully apply if the sum of the load and generation variable is more than 1 (which requires that at least either generation or load HHI is greater than 7000). The effect of this is that the charge would only fully apply where flows are highly concentrated. In other situations, the deeper connection charge would only partially recover costs in relation to an asset, increasing the likelihood that the charge would not significantly depart from a party’s benefit from an asset.

Charge based on HHI to and from regions of electrically related nodes

E.35 The deeper connection charge for an asset would be based on flows through the asset to and from regions of electrically related nodes.

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[281] For example, Transpower (CEG) submission on the options working paper, (p.5, 56 and 78), also ENA (p.7), Unison (p.6).

E.36 Transpower would determine what these regions are in its development of the TPM. The modelling for the charge has been done on the basis that the regions coincide with Transpower's planning regions.

E.37 The Authority is of the view that identifying assets subject to the deeper connection charge using flows from regions of electrically related nodes means that the charge would apply to assets where there is a reasonable likelihood that the parties who would mainly pay charges for the asset would have been or would be prepared to contract for the investment to build it. The deeper connection charge is therefore market-like.

E.38 Transpower's planning regions are shown in Figure 41.

Figure 41: Transpower's transmission planning regions

E.39 Under the envisaged method:

(a) there would be a stronger relationship between a party's use of an eligible investment and charges that the party faces, as compared with the current TPM (although this depends on how the deeper connection charge is allocated, and in particular the extent to which this reflects actual use), but

(b) there would be a weaker relationship between the party's use of an asset and the charges it would face, as compared with a 'pure' flow tracing method, ie a flow tracing method that did not restrict the charge to flow shares above a minimum HHI.

E.40 Previously, the Authority's preference was to determine the deeper connection charge based on flows through the asset to and from customers. However, the Authority was of the view that this would be undesirable because it would incentivise customers to (1) alter their ownership structures to avoid the charge or (2) not alter their ownership structures if doing so would attract additional transmission charges.

E.41 Parties would continue to have the option of negotiating with Transpower for an investment potentially subject to the deeper connection charge through a customer investment contract (**CIC**). Having this option available would promote efficient investment as it would give parties the opportunity to seek assets that better meet their needs than through the regulated transmission investment process.

Broader HHI range for partial application of the charge

E.42 As described above, the deeper connection charge would be applied to recover only part of the cost of an asset if the load and/or generation HHI is between 2,000 and 7,000.

E.43 This is a broader range for partly applying the charge than was proposed in the options working paper, in which a range of HHI=4,000 to HHI=5,000 was proposed.

E.44 The Authority has considered submissions on the options working paper that:

(a) the HHI threshold may lead to firms altering their behaviour to avoid the charge in a way that was inefficient overall[282]

(b) the charge is sensitive to the HHI threshold[283]

(c) the HHI threshold for full application of the charge (HHI=5,000) was arbitrary.[284]

E.45 Having considered those submissions, the Authority now considers that its previous deeper connection charge design would have created incentives for parties to inefficiently avoid the charge, which could have been problematic. The

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[282] For example, in submissions on the options working paper: ENA (p.8-9), EPOC (p.12), Castalia for Genesis (p.18), Tauhara North No. 2 Trust (p.3), Scientia Consulting for Transpower (p.13).

[283] For example, in submissions on the options working paper: Price Waterhouse Coopers representing 21 distributors (p.6-7), NZIER for MEUG (p.20-21), Trustpower (p.14).

[284] For example, in submissions on the options working paper: Counties Power (p.4), Tauhara North No. 2 Trust (p.3).

broader range would mean that customers would face lower incentives to inefficiently change their behaviour to avoid the charge, because the financial benefit from attempts to avoid the charge would be reduced.

E.46 A broader range would help address the risk that using flows to identify deeper connection assets would result in charges being applied to parties that were not willing to contract for the service provided by certain assets. This is because a broad range would limit the degree of recovery in relation to assets where there was a lower likelihood of parties being willing to contract for the asset because it was used by multiple users. However, there would still be some risk that the charge would be allocated to parties for assets for which the parties would not be willing to pay. This risk is partially mitigated by the high threshold for full application of the charge (HHI=7,000).

E.47 The main disadvantage of a broad range is that a significant portion of Transpower's revenue would be recovered through the residual charge. This is a broad-based charge across transmission customers regardless of the services they receive from transmission assets. The larger the residual charge the higher the distortions that arise from it. The Authority has considered two main ways to address this issue: either using an HHI range that uses lower HHI values (eg, 1,000 to 5,000) or applying the deeper connection charge without an HHI threshold.

E.48 Neither option is desirable because:

(a) adopting an HHI range with lower values would result in more revenue being recovered through the deeper connection charge, but is more likely to result in parties being subject to deeper connection charges in relation to assets for which they would not be willing to contract

(b) if the deeper connection charge applied regardless of HHI, the application of the charge would solely relate to use. This would increase the likelihood of a party's charges for at least some assets exceeding that party's private benefit, which is unlikely to be efficient because it would result in the party inefficiently reducing their consumption of transmission services. For example, loop flows may result in parties paying for assets that they would not have willingly paid for. Similarly, it could result in generators paying for reliability investments built to a level of reliability that they would not have willingly contracted for.

E.49 The Authority acknowledges that the cut-off it has chosen may appear somewhat arbitrary. However, the Authority is of the view that the cut-off chosen makes an appropriate trade-off between applying the charges to the parties most likely to benefit from the assets, while limiting the risk that some parties will be charged greater than the benefit they derive from the assets.

Allocation of charge to customers

E.50 As described above, the charge would be allocated to transmission customers based on shares of physical capacity (for load customers) or shares of flows or physical capacity (for generation customers). The proposal to pre-allocate charges to load customers and generation customers according to flows is to ensure that the allocation to load customers and generation customers in aggregate is on the same basis.

E.51 The allocation to load customers based on shares of physical capacity would limit incentives on those customers to inefficiently change their use of the grid to avoid the charge.

E.52 The load variable used in allocating the charge to load customers is intended to prevent load being charged according to their full capacity at nodes involved in flows in relation to a deeper connection asset when their use of the asset is minimal. Without a load variable the rate of the charge relative to their use would be very large and so would provide strong incentives for such load customers to inefficiently alter their behaviour to avoid the charge.

E.53 An allocation to generation customers based on shares of flows would ensure that the charge reflects the service generation customers get from the relevant asset (ie, their use of the asset). This would limit their incentives to inefficiently avoid the charge while maintaining incentives for efficient generation investment. In relation to the latter, charging generators on the basis of shares of flows would mean the charge should be reasonably neutral in terms of investment incentives for different types of generation, ie baseload versus peak versus intermittent generation.

Charge would apply to existing and new assets

E.54 The deeper connection charge would apply to both existing and new assets.

E.55 The Authority considered applying the deeper connection charge to only those assets commissioned after the date of the final guidelines. The Authority decided not to limit the deeper connection charge in that way, because:

(a) the cost-reflectivity problem identified with the current TPM would only be fully addressed over the very long term as assets are replaced. This is because the rate of new investment in the transmission grid may be relatively low in the short- to medium-term. Therefore there will be few assets that are charged on a cost-reflective basis

(b) it would fail to promote efficient investment through failing to make the TPM more transparent and increasing the incentive to scrutinise the efficiency of Transpower's historical investments. Such scrutiny would be beneficial because it would tend to encourage scrutiny of Transpower's future investments, and hence lead to better engagement by stakeholders in the investment process. Enhanced transparency in the grid investment process would also heighten incentives for Transpower to make good investment decisions

(c) applying the charge only to new assets is unlikely to be durable because:

(i) it would not resolve the concern of some stakeholders with the current TPM, that their charges do not reflect the underlying cost of providing them with transmission services

(ii) regions that require major investments in the near future would pay for that major investment, while continuing to pay part of the costs of previous major investments from which they do not benefit.[285]

E.56 It may be argued that (c)(i) and (ii) are about equity, not efficiency. Durability does have an equity dimension, in that if parties do not consider the allocation of charges reasonable they are likely to lobby for change to the TPM. Ultimately this affects efficiency as it increases uncertainty about the TPM and therefore inhibits efficient investment.

Charge based on replacement cost, optimised replacement cost, depreciated historical cost, or optimised depreciated historical cost

E.57 Assets commissioned after the date of the guidelines (until the asset has been commissioned for a period of time specified in the TPM) would be based on replacement cost (**RC**) for the purposes of the deeper connection charge. Note however that, consistent with the proposed area-of-benefit charge discussed in chapter 7, the Authority has not yet taken a firm view on the RC approach.

E.58 The Authority proposed in the options working paper to charge on the basis of depreciated replacement cost (**DRC**) to address the issue of premature, inefficient investment. The Authority now considers that RC charging for the expected life of the asset could be preferable, because it would promote efficient replacement and refurbishment and would also ensure that charges are consistent with service-based charging and promote efficient use of the asset.

E.59 The deeper connection charge would be calculated on the expected life of the asset. The expected life of the asset would be determined by Transpower at the time of commissioning. If it turned out that the actual life was shorter, so there was a loss on disposal and replacement of the asset, the initial book value of the new asset would be increased to take this difference into account. This adjustment would not however be made if the replacement was triggered by force majeure – eg, fire damage or earthquake. If it turned out that the actual life of the asset was longer, the replacement cost would be reduced to zero at the end of its initially expected life in calculating the deeper connection charge.

E.60 The purpose of adjusting the book value at the end of the asset’s initially expected life is so that over time, and force majeure aside, the prices charged for access to the asset accurately reflect its cost, and do not over- or under- recover that cost. The TPM would also provide for an optimisation adjustment, where there has been a material change in circumstances that was not anticipated at the time the asset was constructed.

E.61 Suppose for example that a customer served by an asset subject to the deeper connection charge disconnected from the grid for some reason. In a workably competitive market, the contractual terms between the supplier of services (Transpower in this case) and the customer would determine whether the supplier or the customer in question bore the loss on the asset that was stranded

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285 Several submitters to the options working paper made this point, including for example Orion (p.9) and Alliance Group (p.2).

or significantly underutilised as a consequence of the disconnection. It would be unusual for other customers of the supplier to bear any of the cost.

E.62 However, under Part 4 of the Commerce Act Transpower is able to fully recover its MAR, including where assets have been stranded.

E.63 Accordingly, for an asset commissioned after the date of these guidelines, the Authority would envisage that, for the purposes of determining charges for an asset, Transpower could write down revenue to reflect an optimised asset value in the same circumstances as under the proposed area-of-benefit charge, discussed in chapter 7.

E.64 This approach:

(a) reflects the service provided where there has been a material change in circumstances such as significant technological development or a substantial reduction in demand that is likely to be sustained

(b) efficiently manages the risk of asset stranding and so reduce investment uncertainty by providing all customers with an assurance that there is a limit to how much direct additional cost they will have to bear because other customers change their use of the asset.

E.65 The optimisation method would be determined by Transpower. Transpower would have the discretion to revise its calculation of optimisation for an asset over time, as demand for the asset changes.

E.66 Assets commissioned before the date of the guidelines would potentially be subject to optimisation based on optimised depreciated historical cost (**ODHC**) for the purposes of the deeper connection charge.

E.67 The reason for this is that:

(a) there are no efficiency gains from charging RC for existing assets. In particular, the concerns expressed earlier about time consistency do not arise. This is because if future changes to the TPM are made proposing a move away from RC, time consistency would imply continuing to use RC for assets that have been subject to RC charges in the past

(b) charging RC for existing assets may lead to:

(i) the recovery of more than the RC (potentially up to double recovery) on some older assets. RC charges for customers with heavily depreciated assets would result in them being charged more than the full cost of the assets they use. This creates a credibility problem for future charging regimes, undermining incentives to invest and use the grid

(ii) substantial changes in charges for some customers as at the implementation date. The resulting wealth transfers may give rise to efficiency issues through providing incentives for inefficient behaviour to minimise the wealth transfers. In addition, they may affect perceptions of fairness and so the durability of the TPM. As with other factors that could undermine durability, this could give rise to uncertainty and therefore adversely affect investment efficiency.

E.68 The discussion on stranded assets in chapter 7 above also applies to the treatment of existing assets. In a workably competitive market, if a supplier and their customer had agreed to contractual terms that involved the customer paying the cost of the asset over its life consistent with DHC, they would not expect those charges to increase simply because the supplier stopped supplying another customer.

E.69 So for consistency with treatment in a workably competitive market, for an asset commissioned before the date of any revised TPM guidelines, the proposed guidelines would provide for the optimisation of pre-guidelines assets.

E.70 Specifically, optimisation of pre-guidelines assets would be permitted in the same circumstances as under the proposed area-of-benefit charge, discussed in chapter 7.

E.71 The Authority has taken into account submissions that charges for historical assets should be on the basis of the optimal assets that would be used to supply the customer rather than the actual asset in place.[286]

E.72 Transpower would be responsible for establishing how the optimisation was undertaken. One way to do it would be to establish the full replacement cost of the current asset and the corresponding optimised asset if it were constructed today, and then reducing the DHC by the ratio of the two.

Charge calculated annually based on a 5-year rolling average of flows

E.73 Transpower would be required to determine the application of the deeper connection charge annually, based on a 5 year rolling average of flows.

E.74 This would smooth out variations between periods, and allow for a gradual change in the charge in response to changing use of the grid, limiting the volatility of the charge.

E.75 In the options working paper, it was proposed that Transpower determine the application of the charge every 5 years, based on flows over the previous 5 years. In proposing a 5-year rolling average of flows, the Authority took into account concerns expressed at workshops and in submissions[287] that the previous approach would fail to take into account major changes in use between HHI calculations (for example, the entry or exit of major load or generation), which would cause variability in the charge, and uncertainty for participants.

E.76 The revised approach would not eliminate variability altogether. Flows (across the HVDC in particular) vary between wet and dry years, so there may be some variability. However, using a 5-year rolling average is likely to keep variability at acceptable levels.

E.77 The deeper connection charge would be based on actual flows, for assets commissioned prior to the deeper connection charge applying. For new assets, the charge would be based on estimated flows. Transpower would forecast flows

[286] Submissions on the options working paper: ASEC for IEGA (p.14), ASEC for Electra and KCE (p.6), Marlborough Lines (p.7), MEUG (p.2), New Zealand Steel (p.1), PowerNet (p.4), Trustpower (p.34), Unison (p.8), Westpower (p.5), Buller (p.3, p.5), Meridian (p.2), Nova (p.3), NZ Energy (p.4), TNT2 (p.2).

[287] For example, Transpower (CEG) submission on the options working paper, (p.72).

to determine charging for the first year, and then use actual flows to determine charging for subsequent years, with charges based on a rolling average of the flows for the years for which the asset had been in use if this was less than five. Such an approach would allow Transpower to publish indicative charges prior to an investment. This would allow customers to consider what charges they were likely to face and, therefore, whether the benefits they would receive from the investment would exceed the charges they would pay.

De minimis threshold would only apply to load customers

E.78 As discussed above, a de minimis threshold would only apply to load customers to limit distortions that could arise from applying the charge on a capacity basis where a party made only minimal use of the asset.

E.79 The Authority previously considered including a demand and injection threshold below which the deeper connection charge would not apply. However, that de minimis threshold would be likely to result in inefficient outcomes (eg, it might incentivise participants to alter their behaviour to avoid the charge[288]).

Transpower to determine how deeper connection charge applies to substations

E.80 The method for applying the flow tracing method to substations would need to be determined by Transpower. The question of how the deeper connection charge applies to substations is a matter of detailed design. Since Transpower has the role of developing the TPM and has the relevant technical expertise, it is best placed to develop a method for determining how the charge applies to substations.

Conclusion

E.81 The deeper connection charge would address some of the major problems identified with the current TPM, and would promote the Authority's statutory objective. In particular, the deeper connection charge would be:

(a) <u>service-based:</u> Customers would face charges for assets that provide transmission services to the regions in which the customers are located. The charge would adapt to changes in flows across the grid as a result of investment and connection / disconnection

(b) <u>cost-reflective:</u> A customer's deeper connection charge would better reflect the cost of providing services to that customer as compared with the status quo. A customer would only pay for assets that support the provision of transmission services to or from the region in which they are located

(c) <u>support the discovery of the need for efficient transmission investment through the transmission investment approval process:</u> Customers would have much stronger incentives to scrutinise transmission investments than they would under the status quo. That is because the main parties paying a deeper connection charge for an asset serving a particular region would be the parties that were mainly receiving transmission services from the asset. This is in contrast to the status quo, where the costs of an investment are

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[288] As identified by the following submitters to the options working paper: Genesis (Castalia) (p. 19), Pioneer (p. 2-3), Transpower (Scientia) (p.14).

spread across all load in the case of interconnection and South Island generators in the case of the HVDC

(d) durable: There would be a correlation between the customers that receive services from an asset and the customers that pay for that asset. Unlike the HVDC and interconnection charge, the deeper connection charge would better ensure that customers receiving transmission services from the asset would contribute to its cost.

E.82 The Authority notes that some parties may face deeper connection charges that exceed the benefit they will receive. The Authority has designed the deeper connection charge to minimise the chance of this happening. This includes incorporating an HHI cut-off, and allowing assets, under certain circumstances to be optimised down. In particular, the chances of it happening are much smaller than the current TPM where many of the parties paying for each asset get little if any benefit from that asset. Ultimately though, if parties remain connected even though they consider their charges exceed their private benefit, this suggests they are obtaining wider benefits from being connected to the grid than reflected through their deeper connection charge.

Modelling results for the deeper connection charge

E.83 The Authority has modelled the deeper connection charge for the period 2017 to 2019. As with all the modelling in this document, the modelling is indicative only as the actual charges depend on the TPM that is developed and approved should this be the outcome of this review.

Examples of assets that would be deeper connection for load, generation or both

E.84 Some assets that are modelled as being paid for primarily by load customers are:

(a) the NAaN circuits

(b) circuits from Bunnythorpe to Wilton

(c) Penrose substation.

E.85 The common feature of these assets is that they convey power from a relatively large number of regions to a relatively small number of regions.

E.86 Some assets that are modelled as being paid for by load and generation customers in roughly equal measure are:

(a) circuits from Ashburton to Twizel

(b) circuits from Huapai to Marsden

(c) Haywards substation.

E.87 Some assets that are modelled as being paid for primarily by generation customers are:

(a) circuits from Bunnythorpe to Tangiwai

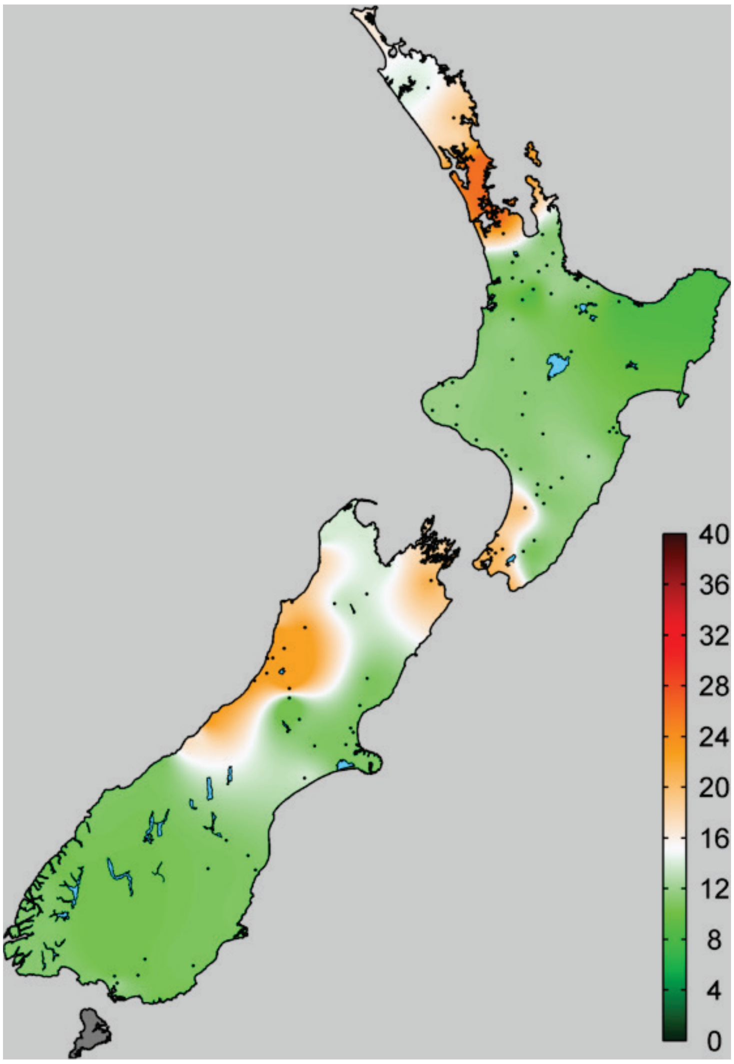
(b) circuits from Rangipo to Wairakei

(c) Stratford substation.

Incidence of the deeper connection charge

E.88 A heat map showing the incidence of the charge on load under the scenario in fully variabilised terms ($/MWh) is shown in Figure 42. Note that charges have been calculated on a DHC and not ODHC basis for historical assets and RC basis for new assets. The modelling can therefore be considered to represent an indication of the highest incidence of possible deeper connection charges.

Figure 42: Incidence of deeper connection charge on load in fully variabilised terms ($/MWh)



E.89 Figure 42 shows that for the modelled scenario, the incidence of the deeper connection charge for load would be greatest in the upper North Island, Horowhenua, Wellington, West Coast and Marlborough regions. However, as the modelled charges are calculated using DHC or RC rather than ODHC or ORC, actual charges may be lower, particularly for regions such as the West Coast, where forecast demand is likely to require assets of lower capacity than those that have been built.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
ACOT	Avoided cost of transmission
AIC	Average incremental cost
AMD	Anytime maximum demand
AHC	Average Historical Cost
AoB	Area-of-benefit
Authority	Electricity Authority
Capex IM	Capital expenditure input methodology
CAPs	Code amendment principles
CBA	Cost benefit analysis
CIC	Customer investment contract
Code	Electricity Industry Participation Code 2010
DG	Distributed generation
DHC	Depreciated Historical Cost
DME framework	Decision-making and economic framework
DRC	Depreciated replacement cost
distributor	Electricity distribution business
ENA	Electricity Networks Association
FTR	Financial transmission rights
GIS	Gas-insulated switch gear
GIT	Grid investment test
GWh	Gigawatt hour
HAMI	Historical anytime maximum injection
HHI	Herfindahl-Hirschman index
HVDC	High voltage direct current
IC	Interconnection
ICP	Installation control point
ICR	Interconnection rate
IM	Input methodology
IPP	Individual price path
IR	Instantaneous reserves

kWh	Kilowatt hour
kvar	Kilovolt ampere reactive
LCE	Loss and constraint excess
LMP	Locational marginal pricing
LRIC	Long-run incremental cost
LRMC	Long-run marginal cost
MAR	Maximum allowable revenue
MEUG	Major Electricity Users' Group
MIC	Marginal incremental cost
MW	Megawatt
MWh	Megawatt hour
MRP	Mighty River Power
NAaN	North Auckland and Northland grid upgrade project
NIGU	North Island Grid Upgrade Project
NRS	Network reactive support
NZAS	New Zealand Aluminium Smelters
ODHC	Optimised Depreciated Historical Cost
ORC	Optimised Replacement Cost
PDP	Prudent discount policy
PDWP	Problem definition working paper
PRS	Price-responsive schedule
RAB	Regulatory asset base
RC	Replacement Cost
RCPD	Regional coincident peak demand
RCPI	Regional coincident peak injection
SFT	Simultaneous feasibility test
SO	System operator
SPD	Scheduling, pricing and dispatch
SRMC	Short-run marginal cost
SRMOC	Short-run marginal opportunity cost
SRS	Static reactive support
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
Transpower	Transpower New Zealand Limited