Transmission Pricing Methodology: Second issues paper

Supplementary consultation

13 December 2016

Executive summary

Introduction

1. The Electricity Authority (Authority) is currently reviewing the guidelines that Transpower New Zealand Limited (Transpower) must follow in developing the transmission pricing methodology (TPM). The TPM sets out how much each transmission customer must pay Transpower in respect of the regulated components of the interconnected grid.

2. The Authority's intention is to improve the TPM so that it better meets the Authority's statutory objective as set out in section 15 of the Electricity Industry Act 2010 (Act):

   > "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".

3. The Authority released the Transmission pricing methodology: Issues and proposal: Second issues paper (second issues paper) in May 2016 and received 508 submissions in July 2016. A summary of those submissions was published on 18 October 2016.[1] Responses to all the issues raised in the submissions will be published separately.

4. Having considered all submissions received to date the Authority believes that the proposed TPM charging framework is fundamentally robust. However, the submissions identified some important refinements that may better promote the Authority's statutory objective. After considering those matters, and other refinements identified by the Authority itself, the Authority has decided it should consult further.

5. This paper is a supplementary consultation paper to the second issues paper. The purpose of this paper is to consult on refinements to the TPM proposed in the second issues paper.

6. The Authority welcomes submissions on the refinements and the corresponding changes to the guidelines. Submissions close on Friday, 24 February 2017.

7. The Authority is currently planning on announcing final decisions on the transmission pricing guidelines in April 2017 but we cannot prejudge the complexity of the issues that may be raised in submission and we will take the time we require to consider that decision.

Background

8. As discussed in the second issues paper, the Authority identified a number of significant issues with the current TPM that do not promote the long-term benefit of consumers. These include:

   (a) the interconnection charge is not service-based or cost-reflective, and sends too strong a signal to avoid peak demand periods

   (b) the high voltage direct current (HVDC) charge provides too strong a signal on generation to avoid locating in the South Island

   (c) there are durability problems with both the interconnection charge and the HVDC charge.

9. The key elements of the TPM charging framework proposed in the second issues paper were:

[1] https://www.ea.govt.nz/dmsdocument/21368.

(a) modification of the existing connection charge

(b) introduction of an area-of-benefit (AoB) charge

(c) a residual charge, which would be a broad-based, low rate charge on load, and not intended to provide any price signal

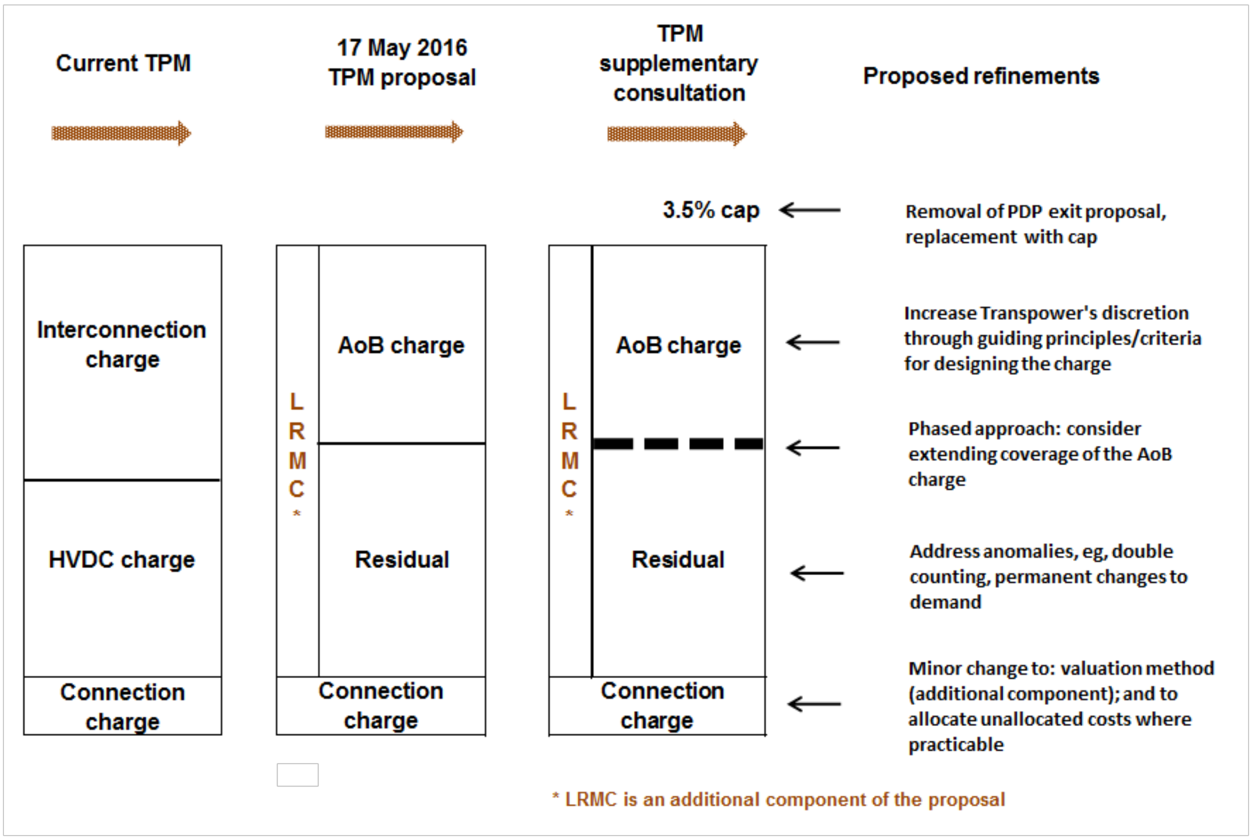
(d) an expanded prudent discount policy (PDP)

(e) potentially, a long run marginal cost (LRMC) charge

(f) potentially, a kilovolt-ampere reactive (kvar) charge.

10. The following diagram provides a stylised overview of the relationship between the current TPM, the proposal as set out in the second issues paper, and the refinements proposed by this paper.

Figure 1 – The relationships between the current TPM, the proposal as set out in the second issues paper, and the refinements proposed by this paper



11. In addition, the Authority proposes:

(a) amending the Electricity Industry Participation Code 2010 (the Code) to ensure that loss and constraint excess (LCE) attributable to specific assets is allocated to customers that pay charges in relation to those assets in proportion to each customer's charges

(b) changing the Code to specify that the minimum power factor is 0.95 in all regions

12. A key theme in submissions was whether a TPM centred around an AoB charge, combined with nodal pricing, is sufficient to promote efficient operation and investment, or whether a peak charge such as the existing RCPD charge or an LRMC charge is required. After considering submissions, the Authority remains of the view expressed in

the second issues paper that the combination of the LCE proposal, connection charge, AoB charge and nodal pricing should be sufficient to promote more efficient operation and investment.

13. In particular, the Authority considers that nodal prices have a key role to play in coordinating electricity consumers' use of the grid so that capacity constraints are not exceeded until new investment is justified. An LRMC charge would only be appropriate in circumstances where nodal pricing is insufficient to signal incremental costs. If Transpower considers this is the case, and it considers that an LRMC charge would be at least as good as the alternative of relying on the price signals from nodal pricing, transmission charges and grid support arrangements to more efficiently defer grid investment, then it could propose an LRMC charge for the Authority's approval.[2] Transpower has indicated in its submission that, if the draft guidelines were confirmed, it would propose an LRMC or an LRMC-like charge.[3]

Proposed refinements

14. The Authority believes the TPM charging framework proposed in the second issues paper is fundamentally robust. However, the Authority has identified a number of refinements that would further enhance the proposed guidelines by:

(a) removing anomalies and making the treatment of similar customers more even-handed so the proposal is more durable

(b) addressing issues with the detail of the proposal identified in submissions and by the Authority that would allow the proposal to better promote the statutory objective

(c) increasing the discretion that Transpower has in designing and implementing the TPM where appropriate to reflect that it would be administering the TPM and that it is often better placed to develop the detail than the Authority.

15. The proposed refinements are as follows:

(a) including an additional component to allow broader coverage for the AoB charge than proposed in the second issues paper with a possible transition[4]

(b) further guidance to Transpower as to how it should trade off accuracy with practicality in the calculation of benefits used to set the AoB charges

(c) a clarification that the calculation of net private benefits for the AoB charge should include any change in LCE payments

(d) a clarification of the cost method for setting the total amount to be recovered in relation to an eligible investment and the total annual AoB charges for recovering the cost of transmission investments, to ensure they are service-based and cost-reflective

(e) a method to provide a proxy for calculating the AoB charge, if calculating it would be otherwise impracticable, and a method to scale back the charges for the

2 Grid support arrangements may include avoided cost of transmission (ACOT) payments made by Transpower and/or distributors, payments that Transpower makes under its demand-response programme and any other form of grid support arrangements made by Transpower and/or distributors.

3 Transpower submission to the second issues paper.

4 As an additional component, Transpower must include it in the TPM if doing so is practicable and consistent with the requirements of clause 12.89 of the Code. This is also true of the other additional components described in this list.

residual charge, overhead and unallocated expenses and the AoB charges on investments made before the publication of the proposed guidelines, if that is necessary to avoid over-recovery of Transpower's revenue

(f) a clarification that optimisation would be available only for high value investments

(g) an additional component to provide that the method for establishing the amount to be charged for connection assets must align with the method for AoB assets

(h) providing that the marginal price adjustment for a new investment be an additional component and apply only to decreases in Transpower's costs

(i) Transpower must seek to make more specific allocation to the AoB charge of overhead and unallocated expenses to the connection assets and eligible investments to which the expenses relate

(j) the load of each customer is to be used to identify who should be liable for the residual charge and the extent to which they are liable

(k) the calculation of the residual charge, and if necessary the AoB charge for load, must follow principles and be less prescriptive

(l) the calculation of the residual charge must be adjusted to avoid double counting and other anomalies (This is covered in the executive summary under the heading above (ie, (k))

(m) the AoB and residual charge of a large consumer to be tied to the consumer

(n) if an LRMC charge is applied, the TPM must specify a method to adjust other transmission charges to take into account revenue recovered by the LRMC charge. The Authority is seeking feedback on which charges should be adjusted

(o) the PDP would not apply to inefficient exit of load or to distributors if one of their load customers faced charges above standalone cost, and would not require a distributor to "build generation" to access a prudent discount for privately beneficial bypass

(p) the TPM should seek to ensure competitive neutrality between grid connected generation, distributed generation (DG) and demand response (DR)

(q) a cap on transmission charges for distributors and direct consumers.

16. The Authority is also seeking feedback on the appropriate fall-back method for allocating the AoB charge to generation.

Allowing for a broader coverage of the AoB charge and a transition

17. The second issues paper proposed that the AoB charge would be applied only for future investments and a few large recent historical investments plus Pole 2 of the HVDC interisland link.

18. Some submissions suggested that the charge should be extended to a wider range of historical investments because:

(a) it would be more consistent with the decision-making and economic (DME) framework

(b) it would be consistent with the findings of the sunk cost working paper that charging for infra-marginal costs, as well as marginal costs,[5] is important for efficiency

(c) it would reduce potential distortions to the location of investment (both load and generation) that uses the grid.

19. For these reasons, the Authority proposes that the guidelines should include an additional component to provide that Transpower must include in the TPM a method for extending the AoB charge to more historical assets than proposed in the second issues paper if doing so is practicable and consistent with the requirements of clause 12.89 of the Code.

20. If Transpower decided to propose a broader coverage of the AoB charge relative to that proposed in the second issues paper, the incidence of charges would be different to that set out in the second issues paper. For example, generators would be likely to bear a greater share of transmission charges, and load customers in the upper North Island would be likely to face lower charges than modelled in the second issues paper. More revenue would be recovered through the AoB charge so less revenue would need to be recovered through the residual charge.

21. If the additional component was included in the TPM, a simplified method or methods for calculating the AoB charge for the further assets would apply, if applying the standard method was not practicable. More information about this is included in the next section.

22. If Transpower extends the AoB charge to more investments it could propose a transition to the new charges.

The calculation of benefits would trade off accuracy with practicality

23. The second issues paper proposed that calculations of the AoB charge would involve use of:

(a) a “standard” method for investments $5m and above, which would involve a more detailed and accurate calculation of benefits

(b) a “simplified” method for investments below $5m, which would involve a simpler and less accurate calculation of benefits.

24. The balance of opinion is that while it could be difficult to assess the private benefit that each transmission customer receives from some new investments, it would be even more difficult for historical investments, particularly for reasonably old historical investments.[6]

25. Therefore getting an accurate assessment of the benefits may be time consuming, expensive, dependent on the assumptions made or otherwise open to judgement. It may be more cost-effective overall to settle for a moderately accurate but less discretionary method for determining benefits.

5 Pacific Aluminium’s submission correctly observed that the main components of the TPM set inframarginal prices to complement the marginal pricing provided by nodal prices. As explained in the sunk costs working paper, marginal costs are cost of producing the last unit whereas infra-marginal costs are the costs of producing all units.

6 For example, Axiom report in Transpower’s submission on the second issues paper.

26. Accordingly, the Authority now proposes that:[7]

(a) the method for calculating benefits for the AoB charge must be based on expected positive net private benefits

(b) the standard method must be as accurate as is reasonably practicable

(c) the TPM must include a simplified method or methods for calculating the AoB charge, to apply to each eligible investment valued at less than $5 million at the time the investment is commissioned or at the completion date, to be applied from the earlier of 3 years after the TPM comes into force, or as soon as reasonably practicable after the standard method has been applied to new investments and pre-guidelines eligible investments as specified in the second issues paper and valued at more than $5 million. A simplified method or methods would be used for estimating the private benefits from pre-guidelines investments, other than eligible investments defined in the second issues paper, if Transpower chooses to subject more pre-guideline assets to the AoB charge, and it was not practicable to apply the standard method in relation to those assets.

(d) in determining the standard and simplified methods, Transpower must weigh the economic benefits of sending accurate price signals against the economic costs of developing and administering the simplified method or the standard method

(e) if the net private benefits cannot be realistically estimated using one scenario, Transpower must calculate those benefits using the arithmetic average of benefits under realistic scenarios. Transpower could seek a determination from the Authority as to whether its estimated benefits were reasonable, if Transpower considers that averaging benefits under likely scenarios does not result in a robust estimate of benefits

(f) the guidelines remove the requirement that AoB charges to generation and load must be allocated so that each group is allocated charges that correspond to the proportion of aggregate benefits the group is expected to receive.

The calculation of net private benefits for the AoB charge to include LCE

27. The second issues paper proposed that the LCE arising from a transmission asset should be allocated to customers that pay the charges for that asset.

28. Some submissions expressed concern that the Authority's indicative modelling did not accurately reflect the benefits that parties gained from an investment. For example, some submitters[8] suggested that charging Auckland/Northland for recent investments is not service-based charging, because they have not in fact seen improvements in reliability and/or quality of supply.

29. Consider, for example, an investment undertaken to relieve congestion caused by a fast growing region. If a region that is not growing benefits from that investment through lower nodal prices, its benefits may be partially or largely offset by its loss in LCE payments. In that case, the fast growing region would be judged to gain relatively more of the benefits from the investment.

7 This is in addition to the requirement proposed in the guidelines in the second issues paper that minimal discretion would be a key factor in the design of the methods for estimating benefits.

8 For example, Air Liquide, Northpower, Top Energy and Vector submissions on the second issues paper.

30. The Authority now proposes to make clear that the calculation of benefits from a new investment should take into account the relative change in private benefits, including any change in LCE payments that result from the investment. This approach should ensure that AoB charges faced by customers better reflects the relative private benefits they expect to obtain from an investment. This should make AoB charges more durable.

The annual AoB charges for an investment to be service-based and cost-reflective

31. The second issues paper proposed that new investments be valued at replacement cost in setting the AoB charge.

32. The second issues paper also proposed that the AoB charge for an investment should recover the forecast capital cost of the investment and the cost of capital on the investment over its useful life, as well as maintenance and operating costs. The Authority remains satisfied that this is appropriate.

33. The Authority agrees with submitters who considered that the charges for transmission investments should be service-based and cost-reflective. The annual services provided by a transmission investment typically do not change much over its useful life. In a workably competitive market, the annual charge for utility-like assets does not vary with the assets' age, because consumers do not value the annual services of a new asset more than an old asset. For that reason, the Authority considers that the annual AoB charge for an older investment should be the same as that for an equivalent new investment. This also means that the annual charge for an investment should be constant over its expected life, apart from an adjustment to reflect changes in the replacement cost of an equivalent new investment.

34. When combined with the requirement in paragraph 32 above, that the total costs of owning and operating the investment should be recovered over its life, this requirement that the inflation adjusted charge be constant provides enough information to establish the annual charge for the investment.

35. The proposed guidelines provide that Transpower would set the AoB charges for both pre-guideline investments and post-guideline investments so that:

(a) the annual AoB charge for an eligible investment increases over time in line with a price index determined by Transpower

(b) the total AoB charges for an eligible investment recover the full cost of every asset (excluding any connection asset) included in the eligible investment (calculated as if the AoB charge had applied to the eligible investment since it was commissioned or completed), including the capital cost of each asset and an allowance for the weighted average cost of capital for the eligible investment.

The Authority refers to this as the indexed historical cost method for setting charges.

36. Transpower may propose in the TPM a method for determining the annual amount to be recovered under the AoB charge that is not based on indexed historical cost, but that is service-based and cost-reflective, if that would better promote the Authority's statutory objective.

37. Transpower must choose a method or methods that promotes an efficient trade-off between the economic benefits of sending a more accurate price signal to customers versus the costs of developing, implementing and administering the valuation method.

38. The proposed guidelines require the TPM to provide for Transpower to alter the time profile of the AoB charge for an investment if the method above would lead to charges that manifestly would not reflect the services provided by the investment at different times in the investment's life.

39. In a workably competitive market, an implication of the annual services being constant over the life of the investment is that the market value of (ie, the replacement cost of) an older investment would be less than the replacement cost of an equivalent new investment. This is because the market value is the present value of the expected cash flows from the investment over the remainder of its expected life. This is also the appropriate way to value most transmission assets for the purpose of the TPM.[9]

40. However, in some cases it will be clear that the services provided by a transmission asset will vary over its life. For example, an investment may be built much larger than initially required in order to accommodate a forecast future substantial step change in forecast demand. This might occur, for example, if it were known that a major new customer was going to enter the market in future. To allow for such cases, it is proposed that the guidelines allow Transpower to alter the charges over the life of the investment to better reflect the services it provides where the services provided by the investment are clearly not constant over its life.

The residual charge, charges for overheads and unallocated expenses and AoB charges for pre-guideline investments may need adjustment

41. While the Authority considers in principle that charging for pre-guideline investments using an IHC or similar approach is appropriate, it may not be practicable. In addition, setting charges on the basis of an IHC or similar approach may lead to an over-recovery of Transpower's recoverable revenue.

42. The guidelines provide that, if it is impracticable for Transpower to establish the amount to be recovered under the AoB charge in relation to the cost of a pre-guideline investment, Transpower could use a suitable proxy.

43. The over-recovery situation arises because Transpower, which recovers costs for its interconnected grid assets on a DHC basis, has been able to front load the recovery of the cost of its past investments (relative to a replacement cost charging basis). This means that there is less remaining to be recovered in the future.

44. If the method for determining the annual amount to be recovered under the AoB charge in relation to pre-guideline investments would result in over-recovery of Transpower's recoverable revenue, the proposed guidelines now provide that the TPM must provide for a method to scale back transmission charges. The scaling would be as follows:

    (a) first, the residual charge (apart from that part resulting from overhead and unallocated expenses) be reduced

    (b) second, to the extent that reducing the residual charge to zero is insufficient to prevent over-recovery of Transpower's recoverable revenue, the charges that recover overhead and unallocated expense be reduced

    (c) third, to the extent that reducing overhead and unallocated operating expenses to zero is insufficient to prevent over-recovery of the recoverable revenue, the AoB

9 As is discussed in the body of the paper, this has no necessary implications for setting Transpower's recoverable revenue, which could be and is calculated in a different manner.

charge for pre-guideline investments be scaled back in a way that best meets the Authority's statutory objective.

Optimisation available only for high value investments

45. The second issues paper proposed that optimisation would only be available on high value investments. The proposed guidelines clarify that, if Transpower proposes that the AoB charge be applied to more pre-guideline investments, optimisation would only be available for those investments that are high value.

Should the fall-back method for allocating the AoB charge be lagged or forecast injection?

46. If allocation of the AoB charge to generation according to net private benefits is not practicable, the second issues paper proposed that the fall-back method should be average injection. This is still the Authority's preferred option.

47. NERA for Meridian has suggested that the fall-back method for allocating the AoB charge to generation could be on the basis of forecast average injection.[10] It suggested that this would be fixed and so less distortionary.

48. The Authority is open to using another method, such as lagged or forecast injection instead of average injection. It is therefore seeking feedback on what would be the best method to use.

Additional component to align the method of charging for connection assets with that for charging for AoB assets

49. The second issues paper noted that if connection assets were valued differently from interconnection assets, it would create an incentive for consumers to seek to have investments reclassified in a way that is most beneficial for them, but inefficient.

50. The Authority proposes that the guidelines should seek to avoid this inefficient incentive by including an additional component to provide that the TPM would align the method for determining the annual amount to be recovered in connection charges in relation to each connection asset with the method for AoB assets, if doing so is practicable and consistent with the requirements of clause 12.89 of the Code.

51. This proposal has been included as an additional component to enable Transpower's initial focus to be the development of the AoB charge. Whether or not Transpower proposes extending coverage of the AoB charge to pre-guideline investments, it would be desirable for Transpower to consider implementing this additional component as soon as it reasonably can after it has completed implementing all aspects of the AoB charge.

The marginal price adjustment for new investment changed to be an additional component

52. The second issues paper proposed that when a transmission customer alters its demand in response to an investment proposal from Transpower, its AoB charge should be adjusted by the saving or additional expenses that Transpower faced.

53. Several submissions raised questions about the value and workability of this proposal.[11]

[10] NERA report, Meridian's submission on the second issues paper.

[11] For example, Trustpower submission on the second issues paper.

54. The Authority now proposes that the marginal price adjustment for a new investment be an additional component, which Transpower could recommend be implemented if that is practicable and consistent with the requirements of clause 12.89 of the Code.

55. The Authority also proposes that if the marginal price adjustment is introduced, it should apply where a customer's actions lead to a reduction in Transpower's costs but not where they lead to an increase. Applying it where the customer's actions lead to an increase in Transpower's costs would encourage customers to conceal their true intentions from Transpower until after it had published its investment proposal. This is because they could then benefit from a marginal rather than an average increase in their AoB charge.

Transpower must seek to make more specific allocation to the connection charge and AoB charge of overhead and unallocated expenses

56. The second issues paper proposed that Transpower's overhead and unallocated operating expenses should be recovered:

(a) from generation designated transmission customers, through the connection charge

(b) from load generation customers, through the residual charge.

57. Some submitters suggested that effort should made to attribute costs to the areas that benefit from the costs being incurred wherever possible, and that where this could be done these costs should be recovered through the AoB charge.[12] The Authority agrees, and considers this principle is also applicable to the connection charge. This would have the benefit of charges being more cost-reflective and of reducing the inefficiencies caused by the residual charge.

58. The Authority therefore proposes that Transpower must seek to attribute expenses currently classified as overhead and unallocated expenses to the connection assets and the eligible investments to which those expenses relate, to the extent that it is practicable to do so. These costs would then be allocated through the connection charge and AoB charge, as appropriate.

59. For the remaining overhead and unallocated expenses, one submitter considered that a surcharge approach would be preferable to the Authority's proposed approach on the basis that it would be service-based and cost-reflective.[13] Other submitters agreed with the Authority's proposed approach.[14] The Authority is of the view that its proposed approach is preferable, because it is closer to how a business in a workably competitive market would actually recover its costs.

The load of each customer is to be used to identify who is liable for the residual charge

60. Some submitters pointed out that applying the residual charge to load customers but not generation customers creates a difficult boundary issue since a customer can be at different times both load and generation.[15]

12 For example, Pacific Aluminum's submission on the second issues paper.

13 Pacific Aluminum's submission on the second issues paper.

14 For example, Oji Fibre submission on the second issues paper.

15 Counties Power submission to the second issues paper.

61. The Authority agrees with these submissions. The proposed guidelines now provide that the load of each customer is to be used to identify who is liable for the residual charge and the extent to which those customers must pay.

Calculation of the residual charge and if necessary the AoB charge for load must follow principles and be less prescriptive

62. The second issues paper proposed that the residual be allocated to load on the basis of historical capacity, measured as one of historical gross AMD, line capacity or transformer capacity.

63. Some submitters suggested that:

(a) line capacity and transformer capacity were poor measures of capacity

(b) the guidelines were too prescriptive

(c) the configuration of some customers' transmission assets appeared to inflate their residual charge relative to other similar customers

(d) historical capacity may not be a reasonable proxy for current capacity because of changes in demand over time.

64. The Authority considers that these submissions are valid. As a result, the residual (and if necessary the AoB charge) would also be allocated to customers load (see above section) according to historical AMD or another method. Whichever method is used, it needs to:

(a) be**,** to the extent that it can be economically achieved, designed to ensure that the quantum of residual charge that load is charged cannot change either as a consequence of its own actions or the actions of any other party (except Transpower). This is so that the allocation method does not create incentives or opportunities for designated transmission customers to inefficiently avoid the residual charge

(b) be related to the size of the customer's load, so that the allocation of charges is durable

(c) be designed so that any DG that is paid or credited for transmission charges avoided by the relevant distributor would not receive such payment or credit in respect of the residual charge component of the relevant distributor's transmission charges (for example by adding back a value representing the load supplied by the DG for the purpose of calculating the residual charge)

(d) use load to determine the customers that must pay the residual charge and the extent to which they must pay

(e) correct for double counting and other anomalies

(f) result in broadly equivalent charges to customers that are in broadly equivalent circumstances

The AoB and residual charge of a large consumer to be tied to the consumer

65. Because the residual charge is designed not to change with a customer's load, it raises the potential for a large consumer to shift from its existing supplier to a new supplier and avoid the residual charge. This is inefficient.

66. To avoid this situation, it is proposed that if a large consumer shifts its supplier, its AoB charge and residual charge would shift with it.

67. This would not apply to a smaller consumer where the private benefits of shifting supplier would be outweighed by the cost.

68. For the purposes of the above, a shift that takes place in the period from 13 December 2016 to the date the TPM comes into force is deemed to have occurred on the date that the TPM comes into force.

If an LRMC charge is applied, the TPM must specify a method to adjust other charges

69. The second issues paper proposed that if an LRMC charge is introduced the revenue recovered from the LRMC charge would be offset by a reduction in the residual charge.

70. Transpower submitted that if an LRMC charge is imposed, it would be desirable to reduce the AoB charge correspondingly, not the residual, so that the combination of the LRMC charge and the AoB charge did not over-signal future transmission costs.[16]

71. The Authority considers that an LRMC charge is most likely to be needed to ration the use of the existing grid to efficiently defer new investment when for some reason nodal prices are not effective in doing so. It also considers that the need for an LRMC charge may be deferred by using other forms of grid support payments to defer the need for future grid investment, when that is more efficient.

72. The Authority currently proposes that if an LRMC charge is included in the TPM, the TPM must specify a method for adjusting transmission charges to take into account revenue recovered by the LRMC charge. However, the Authority is open to being more specific. The Authority would welcome submissions on its views about the LRMC charge and whether changes are needed to other charges.

73. The guidelines also clarify that when Transpower is considering an LRMC charge, it must be considered in the context of all the ways that Transpower has of efficiently deferring investment.

The PDP would not apply to inefficient exit

74. The second issues paper proposed that the PDP should be extended, including to situations where there was a material risk that an electricity consumer would close its New Zealand plant ("inefficient exit"). It also proposed that the PDP would apply to embedded customers in some circumstances.

75. Some submissions suggested that:

(a) this inefficient exit provision might increase inefficiency as a consumer might be exiting simply because it was less efficient than its competitors

(b) in some cases the prudent discount would amount to an inefficient subsidy

(c) the customer would have superior information to the authority granting the prudent discount, and it could therefore expend resources in an attempt to get a prudent discount when one was not in fact justified.[17]

76. The Authority accepts that these concerns are material, and has therefore decided not to proceed with the inefficient exit provision.

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16 Transpower submission on the second issues paper.

17 Business NZ, Fonterra, Trustpower, Orion, Transpower submissions on the second issues paper.

77. The guidelines proposed in the second issues paper also allowed for a prudent discount to be available if it is privately beneficial for a load designated transmission customer to build generation to disconnect from the grid, but not in the long-term benefit of consumers.

78. Several submitters[18] suggested that a PDP should be available to a distributor that has DG customers that make it privately beneficial for the distributor to inefficiently disconnect from the interconnected grid.

79. It was the Authority's intention that a prudent discount would be available in these circumstances. Accordingly, the proposed guidelines no longer require that the relevant distributor "build generation" in order to qualify for a prudent discount, to give effect to this intention.

80. The Authority also proposes to remove the condition that a prudent discount might apply to an embedded load customer of a distributor whose charges exceed standalone cost. This is because it is in the distributor's hands to lower its customer's charges.

Maintaining competitive neutrality between grid connected generation, DG and DR

81. The second issues paper proposed that the residual charge would not be applied to direct connect generation but would be applied to load.

82. Some distributors have indicated that they would pass on the residual charge to DG in some circumstances. This may not be competitively neutral, so it could allow some less efficient direct connect generation to displace more efficient DG.

83. At this stage, the Authority has decided not to remove the provision under the distributed generation pricing principles (DGPP) that distributors can charge DG no more than incremental cost. This will avoid the problem discussed in the previous paragraph.

84. However, for the sake of clarity, the proposed guidelines include the principle that the TPM should seek to maintain competitive neutrality between grid connected generation, DG and DR.

Cap on transmission charges

85. The second issues paper did not propose a transitional provision. This was because the modelled indicative initial impact for almost all residential consumers was modest. The largest increase in the final electricity bill of residential consumers was modelled to be 5.8%. For some larger industrial plants the indicative initial impact would have been higher. However, these industrial plants would have been eligible to apply for a prudent discount for inefficient exit.

86. The refinements proposed in this paper introduce greater uncertainty for consumers, particularly the greater flexibility for Transpower to design the residual charge and the reduced scope of the prudent discount policy.

87. The proposed guidelines, therefore, provide for a cap on transmission charges to distributors and direct consumers. The cap would not apply to generators (who pay a relatively small residual charge) even if they have load.

88. The proposed cap is expressed in relation to a base value for each year. For a distributor, the base value is the estimated total of the electricity bills (including all charges in respect of transmission, distribution, energy, levies and taxes) of all the

[18] For example, PwC (for 14 distributors) and Top Energy submissions on the second issues paper.

distributor's customers in the 2019/20 pricing year, plus inflation (CPI). For a direct connect consumer, the base value is the direct consumer’s estimated total electricity bill in the 2019/2020 pricing year (including all charges in respect of transmission, distribution, energy, levies and taxes), plus inflation (CPI).

89. The proposed cap is also expressed in relation to a "net charge". For a distributor, the net charge will include the estimated sum of the electricity bills of all of the distributor's customers for the year (including all charges in respect of transmission, distribution, energy, levies, and taxes). For a direct consumer, the net charge will include the direct consumer's estimated total electricity bill for the year (including all charges in respect of transmission, distribution, energy, levies and taxes). In both cases, the net charge will be exclusive of any amount payable by the distributor or direct consumer for the year in respect of an LRMC charge, kvar charge, any charge attributable to assets commissioned after the end of the 2019/20 pricing year, any AoB charge for further assets included as eligible investments under the additional component, and any increase in the distributor's or direct consumer's uncapped charges as a result of the optimisation of an investment or a material change in circumstances.

90. The amount of the cap is:

(a) For each distributor 103.5% of the distributor’s base value in that year

(b) For each direct consumer 103.5% of the direct consumer's base value. The level of the cap for a direct consumer starts to rise by two percentage points per annum three years after the date the TPM comes into force or when Transpower extends the AoB charge to other pre-guidelines assets if it does so and that occurs earlier. That is, in the first year the percentage increases, the cap rises to 105.5% of the direct consumer’s base value in that year, the next it rises to 107.5% of the direct consumer’s base value in that year, and so on.

91. The guidelines require the TPM to provide that, if a distributor's or direct consumer's transmission charges would increase in a year such that the distributor's or direct consumer's net charge would exceed the amount of the cap, Transpower must reduce the distributor's or direct consumer's transmission charges for the relevant year such that the net charge does not exceed the amount of the cap.

92. If a distributor's or direct consumer's total transmission charges, less the components specified in the next sentence would be below incremental cost in a year, those charges must be set at the incremental cost. The components deducted in the previous sentence are the amount payable by the distributor or direct consumer for the year in respect of an LRMC charge, kvar charge, any charge attributable to assets commissioned after the end of the 2019/20 pricing year, any AoB charge for further assets included as eligible investments under the additional component, and any increase in the distributor's or direct consumer's uncapped charges as a result of the optimisation of an investment or a material change in circumstances.

93. If in any year the cap does not result in a reduction in transmission charges for a distributor or direct consumer, no cap applies to the distributor's or direct consumer's transmission charges in any subsequent year.

94. If there is a material increase in a distributor’s or direct consumer’s load, Transpower would be required to adjust the cap on the distributor’s or direct consumer’s transmission charges by the same percentage as the increase in the customer's load.

95. If the cap would prevent Transpower from recovering its recoverable revenue, all caps would be increased proportionately to the extent necessary so that it is possible for Transpower to recover its recoverable revenue.

96. Transpower would be required to review the operation of the cap in relation to the distributors and direct consumers whose charges continue to be reduced by the cap, to be carried out in 2025 and completed not later than the end of that year.

97. Distributors face the transmission charges and benefit from the cap, rather than their customers. This provides them with the opportunity but not the requirement to limit any increase in their customers' electricity bills, including households' bills, to no more than 3.5% above inflation.

Supplementary consultation modelling results

98. Appendix F provides the supplementary consultation modelling results. Two modelling scenarios are presented, each estimating the charges for the first year of implementation of the TPM proposal.

99. Scenario 1 includes:

(a) the proposed cap to limit initial increases in transmission charges as described above

(b) the North Island grid upgrade (NIGU) investment remodelled (as discussed below)

(c) transmission and distribution charges adjusted to reflect the possibility that a lower weighted average cost of capital (WACC) will apply for Transpower and regulated distributors for Regulatory Control Period 3 (RCP3), which commences from April 2020

(d) some anomalies addressed.

100. The charts and tables in scenario 1 show that changes in the WACC could more than offset changes to the TPM.

101. The 'status quo' is the current TPM and the current WACC for the regulatory period 2015-2020. The charts and tables therefore do not provide a comparison with what would happen under the current TPM with a WACC adjustment.

102. Scenario 2 includes the same effects as scenario 1 except that it does not include the WACC adjustment to Transpower and distributors that is assumed to apply for RCP3.

103. The main changes to indicative transmission charges (shown as $/MWh) for scenario 1 can be seen in Figure 2, with the circle markers showing the indicative charges arising from the proposals in the second issues paper and the orange columns showing the indicative charges of all of the proposed changes (ie, including the refinements discussed above), the cap and the estimated possible change in WACC.

104. Relative to the proposal in the second issues paper, the refinements and the potential WACC reduction result in:

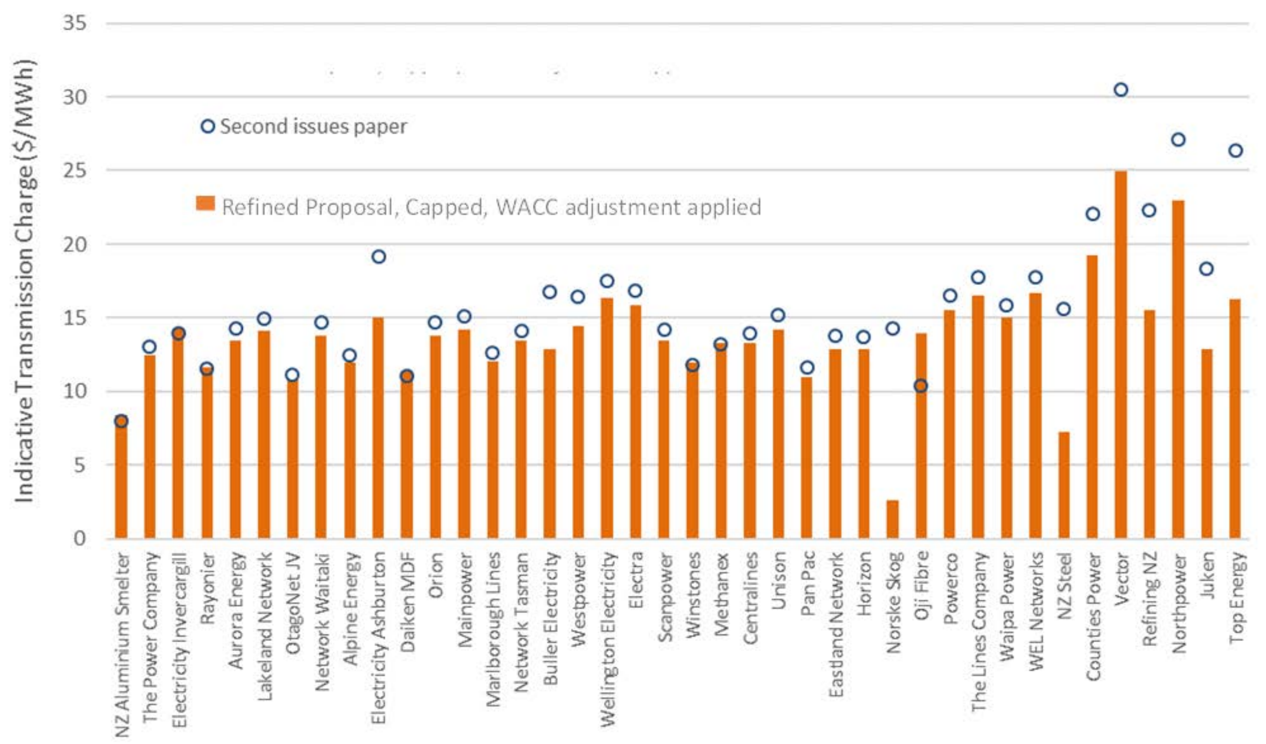
(a) a reduction to almost all parties' transmission charges due to the possible reduction in Transpower's WACC

(b) a material reduction in parties' transmission charges where anomalies in the demand data have been addressed (eg, see Electricity Ashburton, Westpower, Buller)

(c) a material reduction in Top Energy's transmission charges arising from the remodelling of the NIGU investment with 25 MW added to Ngawha's generation[19]

(d) a reduction in proposed transmission charges for parties whose charges have been capped.

Figure 2 – Scenario 1 transmission charges as $/MWh with parties sorted geographically (all changes, 2020 impact)[20]



105. Some parties' residual charges increase to fund the cap. Further, the cap on direct consumers will rise by two percentage points per annum three years after the implementation of the revised TPM (or when Transpower applies the AoB charge to pre-guidelines assets, whichever is first).

106. Figure 3 shows the combined impact (in %) of all these changes relative to the status quo–in which there are no changes to the TPM or to the WACC (ie, the status quo is the horizontal line, reflecting 0% change). The bars represent the estimated effect on consumers' electricity bills under each party (the possible reduced WACC for distributors has a significant effect here).

107. The main result shown in this chart is the overall reduction in residential consumers' electricity bills, which mainly arises from the possible WACC reduction for Transpower and distributors. Further, four of the direct customers' charges are affected by the capping mechanism.

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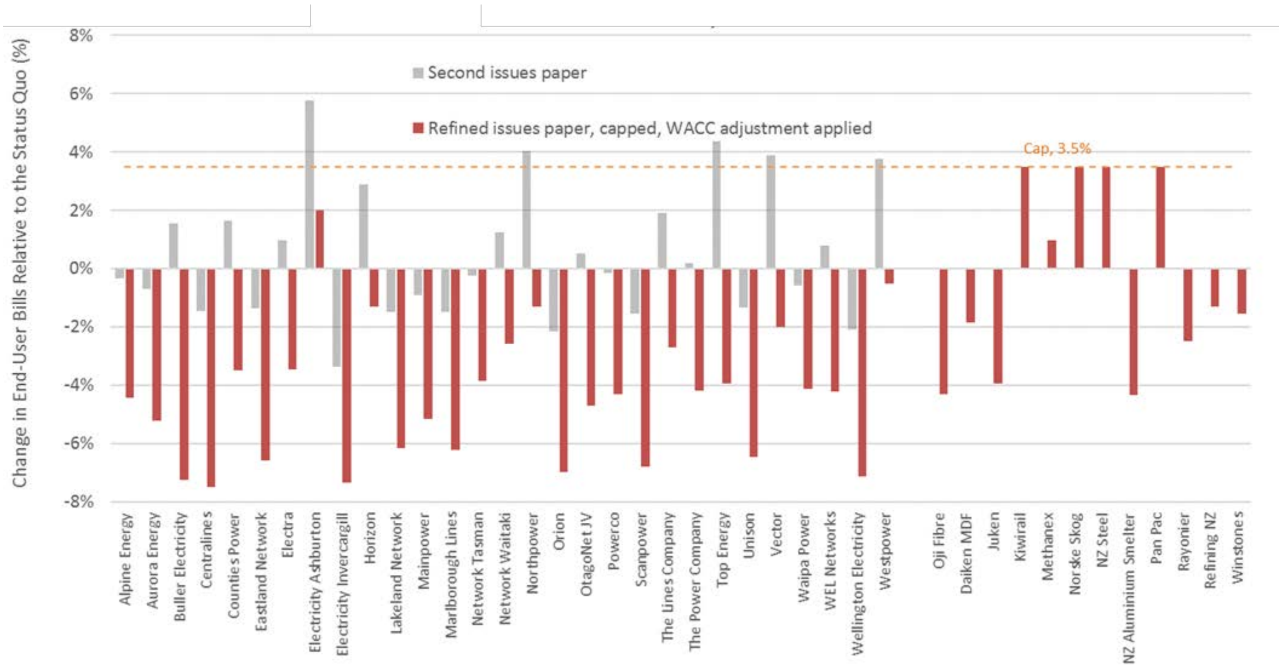
19 Other parties in the upper North Island (UNI) who are allocated AoB charges from the NIGU investment also see a reduction in charges due to the remodelling of the NIGU investment. This occurs because flow into the entire UNI is constrained less often.

20 KiwiRail has been left out due to scaling. Please refer to Tables 2 and 7 in Appendix F for KiwiRail's charges in $/MWh.

Figure 3 – Scenario 1 percentage change in consumers' electricity bills relative to status quo (all changes, 2020 impact)



108. Table 1 below shows the indicative impact (in $/year) on a typical household's electricity bill relative to the status quo for scenarios 1 and 2, whereas table 2 provides the indicative impact on major industrials' transmission charges (in $million/year) for scenarios 1 and 2.

109. Refer to Appendix F for a more comprehensive description of the modelling results.

Table 1: Scenarios 1 and 2 indicative impact ($/year) on a typical household's electricity bill relative to the status quo (2020 impact)

Indicative household impact relative to the status quo ($/year)	Second issues paper	Scenario 1 Refined issues paper, capped, all changes	Scenario 2 Refined issues paper, capped, no change to WACC
Alpine Energy	-6	-75	3
Aurora Energy	-14	-90	-5
Buller Electricity	26	-63	15
Centralines	-29	-129	-22
Counties Power	33	-63	29
Eastland Network	-24	-101	-19
Electra	14	-47	21
Electricity Ashburton	117	30	54
Electricity Invercargill	-64	-125	-44
Horizon	46	-19	43
Lakeland Network	-33	-119	-23
Mainpower	-19	-97	-10
Marlborough Lines	-31	-110	-23

Indicative household impact relative to the status quo ($/year)	Second issues paper	Scenario 1 Refined issues paper, capped, all changes	Scenario 2 Refined issues paper, capped, no change to WACC
Network Tasman	-4	-56	4
Network Waitaki	21	-40	29
Northpower	63	-17	46
Orion	-44	-124	-35
OtagoNet JV	12	-93	20
Powerco	-2	-79	-8
Scanpower	-28	-108	-21
The Lines Company	41	-52	49
The Power Company	4	-81	14
Top Energy	87	-64	40
Unison	-25	-106	-19
Vector	66	-35	41
Waipa Power	-10	-63	-1
WEL Networks	14	-65	21
Wellington Electricity	-35	-104	-28
Westpower	66	-5	53

Table 2: Scenarios 1 and 2 indicative major industrials transmission charges as $m/year (2020 impact)

Indicative charges in $ per year	Status quo charge	Second issues paper	Scenario 1 Refined issues paper, capped, all changes	Scenario 2 Refined issues paper, capped, no change to WACC
Oji Fibre	6	6.7	7.2	8.1
Daiken MDF	0.9	0.8	0.8	0.9
Juken	0.44	1.13	0.71	0.81
Kiwirail	0.5	2.3	0.7	0.7
Methanex	0.7	0.7	0.7	0.8
Norske Skog	0	6.8	1.3	1.3
NZ Steel	4.6	16.6	7.6	7.6
NZ Aluminium Smelter	60.8	40	41.9	47.4
Pan Pac	4.3	6.2	5.8	5.8
Rayonier	0.7	0.6	0.6	0.7
Refining NZ	3.4	4.8	4.1	4.3
Winstones	3.2	2.8	2.8	3.2

Cost benefit analysis – response to submission and impact of the refinements

110. The Authority asked Oakley Greenwood (OGW) to reconsider its cost-benefit analysis (CBA) following its consideration of submissions on the second issues paper CBA.

111. One of the main issues identified by submitters was uncertainty about the benefits that OGW identified. While OGW recognised that there was uncertainty in the CBA, its view is that the sensitivities undertaken adequately address this uncertainty.

112. OGW commented that, given the CBA is in relation to guidelines and not a detailed methodology, it is appropriate to model a generic approach that is consistent with service-based and cost-reflective pricing. According to OGW, leaving aside transactions and similar costs, applying a service-based and cost-reflective approach should lead to increased efficiency, not because it is assumed but because economic theory is clear that it will. OGW does not consider any changes are required to its CBA in response to submissions on the second issues paper CBA.

113. The Authority has considered both submissions and OGWs response. The Authority is still of the view that OGW's analysis provides a reasonable assessment of the net benefits arising from the benefits and costs it has quantified.

114. The Authority further requested OGW reconsider their CBA on the basis of the proposed refinements.

115. The refinement to remove the prudent discount policy (PDP) for inefficient exit of loads was the only refinement OGW considered would have a quantitative impact on their CBA. This is because the proposed change could preclude a customer from accessing a PDP when the customer's willingness to pay for transmission services is less than the transmission pricing levels that they currently face, but above Transpower's avoidable cost of supply. If a customer in those circumstances cannot access a PDP, the customer may be forced to (inefficiently) disconnect from Transpower's network.

116. The Authority has also considered the impact of its decision on the DGPP on its CBA. The Authority expects most of the gain from the DGPP decision to come from reduced investment in inefficient renewable generation connected to distribution networks, but not behind end consumers' meters. Conversely, OGW's analysis of DG focused more on the construction of smaller scale, diesel generation sets that could in theory be located behind an end consumer's meter. Furthermore, OGW did not explicitly consider the incentives under the arrangements prior to the change to the DGPPs to encourage inefficient investment in 'grid-side' renewable DG. Any reduction in such investment would have been a potential source of additional benefit in OGW's analysis, had they considered it. This would have provided another unquantified benefit of the Authority's original proposal.

117. Given these factors, the Authority considers that the effect of the DGPP decision on quantified net benefits from the proposed TPM guidelines is likely to range between no impact and a reduction of $23 million, and more likely towards the smaller end of this range.

118. Leaving aside this uncertainty, overall the quantified expected net benefits in the OGW CBA reduce from $213.3m to $203m due to the proposed refinements. This reduction reflects the omission of the benefit that OGW modelled for the PDP for inefficient exit. Because the Authority now believes the costs of the PDP for inefficient exit would exceed the benefits, the Authority's view is that in this respect the original OGW CBA

overestimated the net benefits of its proposed guidelines by this amount. In other words, in reality, there is no loss of benefit from removing the inefficient exit provision.

119. The Authority agrees with OGW that in other respects the refinements will not significantly reduce the expected quantified net benefits of the proposal. However, as the second issues paper made clear, the Authority is of the view that OGW has been highly conservative in its assessment of non-quantified benefits from the proposed TPM including the refinements, including in particular the efficiency impacts of increased scrutiny of transmission investments and from durability.

Overall impact of the refinements

120. The overall impact of the refinements mostly depends on two factors: (1) the extent to which Transpower proposes to extend the coverage of the AoB charge beyond what was proposed in the second issues paper, and the related transitional arrangements and (2) the proposed cap.

121. To the extent that Transpower does not expand the coverage of the AoB charge, the effect of all the other refinements to the proposed guidelines in the second issues paper on all load parties is likely to be modest apart from any limits to increases in charges caused by the proposed cap.

122. If Transpower chose to extend the AoB charge to all pre-guideline investments, the impact would be more substantial, but might be mitigated by any transitional arrangements that Transpower proposes. Leaving aside the transitional arrangements, grid-connected generation would face an increase in AoB charges relative to the proposal in the second issues paper. Overall charges on load would reduce correspondingly and shift from load that most benefited from the post-2004 investments to other load that faced relatively small AoB charges under the proposed guidelines in the second issues paper. The guidelines allow Transpower to propose transitional arrangements for charges on additional AoB investments, which would mitigate these effects.

123. For DG, the Authority has decided that distributors should continue to charge DG the incremental cost of their connection, so there should be limited impact on DG from the proposed refinements. There may however be some impact on DG connected to distributors that inject into the interconnected grid.

124. If Transpower chose to extend the AoB charge to some more, but not all pre-guideline investments, the impact would depend on which pre-guideline investments it chose. However, it is likely that charges on generation would increase relative to the second issues paper proposal and the residual charge would reduce. Any increases in charges would likely be moderated by transitional arrangements that Transpower may propose if this applied to generation.

125. Beyond this, the proposed guidelines would be more durable, because of the cap on charge increases, the removal of anomalies, the reduction in the residual charge arising from any extension of the AoB charge to more pre-guideline investments, and the removal of access to the PDP for inefficient exit.

Assessment against the statutory objective and the Code Amendment principles

126. The Authority has reviewed its “Evaluation of the proposal against the Authority’s Statutory Objective” and its “Evaluation of the proposal against the Authority’s Code

Amendment Principles” in the second issues paper in light of the refinements proposed in this supplementary paper.

127. The Authority considers that the refinements of the proposal have little impact on its conclusion there. Moreover, it considers that, to the extent they do have an impact, they enhance the proposal’s contribution to the statutory objective overall. The Authority also considers that the proposal remains consistent with the Authority’s Code Amendment Principles.

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1. Introduction

Background

1.1 The Electricity Authority (Authority) is reviewing the guidelines that Transpower New Zealand Limited (Transpower) must follow in developing the transmission pricing methodology (TPM). The TPM sets out how much each transmission customer must pay Transpower in respect of the regulated components of the national electricity grid (the grid).

1.2 The current TPM guidelines are available on the Authority's website[21] and the current TPM is set out in Schedule 12.4 of the Electricity Industry Participation Code 2010 (Code). 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.

About this paper

1.4 This paper is a supplementary consultation paper to the Transmission pricing methodology: Issues and proposal: Second issues paper (second issues paper) published in May 2016 under clause 12.81 of the Code.[22]

1.5 Submissions on the second issues paper identified several refinements to the proposal in the second issues paper that appear likely to better promote the Authority's statutory objective. The purpose of this paper is to consult on those refinements. The proposed refinements are set out in chapter 3 of this paper.

1.6 The refinements would:

(a) better ensure the proposal provides for service-based and cost-reflective pricing

(b) address some charging anomalies for particular parties, which would improve the durability of the proposal

(c) allocate development of detail to which of the Authority or Transpower is better placed to develop details.

1.7 Revised draft guidelines based on the Authority's proposals with the proposed refinements are set out in Appendix E of this paper.

Submissions

1.8 The Authority invites interested parties to consider the proposed refinements and make submissions.

1.9 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

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

22 Transmission pricing methodology: Issues and proposal: Second issues paper, 17 May 2016, available at: https://www.ea.govt.nz/dmsdocument/20716.

possible to send submissions electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with 'Transmission Pricing Methodology: Second issues paper: Supplementary consultation' in the subject line.

1.10 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

1.11 Submissions should be received by 5pm on Friday, 24 February 2017. Late submissions are unlikely to be considered.

1.12 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.

1.13 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 in the TPM review process

1.14 The Authority intends to publish responses to points made in submissions received on the second issues paper.

1.15 After submissions are received on this paper, the next steps are:

(a) the Authority will publish submissions

(b) the Authority will consider submissions and consider whether there would be benefit from cross-submissions, a hearing, or other process steps

(c) the Authority will publish a summary of submissions received

(d) the Authority may finalise and publish guidelines for Transpower to follow in developing a new TPM and a process for the development of the TPM.

1.16 .The Authority is currently planning on announcing final decisions on the transmission pricing guidelines in April 2017 but we cannot prejudge the complexity of the issues that may be raised in submissions and we will take the time we require to consider that decision.

2 Why the Authority is proposing refinements to the proposed guidelines

Introduction

2.1 This chapter sets out why the Authority is proposing refinements to the draft guidelines proposed in the second issues paper.

Problem definition

2.2 Many submissions recognised that the current TPM causes the problems, or some of the problems, identified in the second issues paper. Submissions included the following:

(a) the interconnection charge causes too strong a price signal to avoid peak demand periods[23]

(b) the interconnection charge may not be service-based and cost-reflective, and that this problem may get worse if there is increased transmission investment to facilitate growth in particular areas[24]

(c) the HVDC charge provides too strong a signal on generation to avoid location in the South Island[25]

(d) there are durability problems with both the HVDC and interconnection charges[26]

(e) there are issues with the calculation of the connection charge that should be addressed[27]

(f) the current power factor requirements in the Electricity Industry Participation Code (Code) are problematic as they are impossible to comply with.

2.3 Some submitters questioned whether some or all of the problems identified were real or as substantial as the Authority suggested.[28] Others thought that a review of the TPM guidelines was unnecessary.[29] The Authority will respond to these points when it publishes its response to points raised in submissions on the second issues paper (response to submissions).

2.4 Having taken account of these submissions, the Authority remains of the view that addressing the problems it has identified requires new TPM guidelines.

The proposed TPM charging framework is robust

2.5 The Authority's proposal in the second issues paper provided for the following charging 'framework':

23 For example, EA Networks submission on the second issues paper.

24 For example, Stabicraft submission on the second issues paper.

25 Meridian, submission on the problem definition working paper. Note that this is a different problem to that addressed by calculation of the charge from historical anytime maximum demand (HAMI) to South Island mean injection (SIMI), which addressed the problem that calculating the charge according to HAMI discouraged South Island generators from operating at full capacity.

26 For example, Meridian submission on the second issues paper.

27 For example, Contact Energy submission on the second issues paper.

28 For example, PwC submission on the second issues paper.

29 For example, Powerco submission on the second issues paper.

(a) the existing connection charge, potentially with changes to address problems that have been identified with this charge

(b) an area-of-benefit (AoB) charge

(c) a residual charge, which would be a broad-based, low rate charge on load, and not intended to provide any price signal

(d) an expanded prudent discount policy (PDP)

(e) potentially, a long run marginal cost (LRMC) charge

(f) potentially, a kilovolt ampere reactive (kvar) charge.

2.6 In addition, the Authority intends:

(a) to change the Code to ensure that loss and constraint excess (LCE) attributable to specific assets is allocated to customers that pay charges in relation to those assets in proportion to each customer's charges

(b) to change the Connection Code to specify that the minimum power factor is 0.95 in all regions.

2.7 Submitters were divided as to which charge, other than the connection charge, should be the main charge used to promote efficient use of the grid and efficient investment if the TPM was changed so it was more service-based and cost-reflective. In general, submitters favoured either:

(a) an AoB charge, or

(b) a charge which explicitly signalled the cost of future transmission investments before they occurred, such as an LRMC charge.

2.8 The view expressed in the second issues paper was that the combination of an AoB charge and nodal pricing was sufficient to promote more efficient investment. However, if Transpower considered this was not the case, and it considers an LRMC charge would be superior to relying on other forms of grid support payment to more efficiently defer grid investment, then it could propose an LRMC charge for the Authority's approval. Transpower indicated in its submission that, if the draft guidelines were confirmed, it would propose an LRMC or an LRMC-like charge.[30]

2.9 Submitters that questioned the AoB charge suggested that an LRMC charge:

(a) is preferred under the Authority's decision-making and economic framework

(b) provides a more efficient price signal

(c) does not rely on parties subject to the charge understanding Transpower's investment proposals and responding to the prospect of a future charge that would apply after the investment was made

(d) does not rely on other parties subject to the charge also taking action to defer the investment (the so-called "tragedy of the commons" problem).[31]

2.10 The Authority broadly agrees with the OGW assessment[32] in the cost benefit analysis (CBA) of the proposal in the second issues paper that there are a number of conditions

30 Transpower submission on the second issues paper.

31 Axiom report, Transpower submission on the second issues paper.

32 OGW CBA, section 7.2.1.

that must be met for the AoB charge to cause customers to take account of the effect of their actions on transmission costs. Specifically, customers must:

(a) understand there is a clear link between their actions and their future AoB charges in relation to an investment prior to them undertaking the action

(b) be aware of the price signal when they make their own investment or consumption decisions in response to that price signal, and have these changes flow through to the costs Transpower incurs

(c) not be incentivised to change their behaviour after the transmission investment has been made, in order to change their future stream of payments for that investment.

2.11 Regarding 2.10 (a) and (b), some submitters argued that some consumers would not anticipate future AoB charges, either because they would not be forward looking or because they would not get the information to make forward looking decisions.

2.12 The Authority is of the view that Transpower will have an incentive to provide this information to its customers. It also considers that distributors will have the incentive to ensure that its customers are aware of and take account of future increases in transmission charges.

2.13 Regarding paragraph 2.9 (d), some submitters suggested there would be a "tragedy of the commons" situation with respect to new grid investment. If there were many beneficiaries of an investment, most would know that their own actions would have no significant impact on the timing of investment. They would therefore continue to use the grid as if there was no AoB charge for the new investment. This would lead to inefficiently early investment.

2.14 The Authority agrees with submitters that there is a need for some mechanism to prevent inefficiently early investment. However, the Authority is of the view that submitters' concerns are overstated. Provided nodal prices are allowed to operate to limit the use of the grid to its capacity until new investment is justified, nodal price signals will coordinate grid use among different parties so that the available capacity is used by those that benefit most from it. As the second issues paper states, "the transport charge inherent in nodal prices provide 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". Thus grid users act as if they are coordinating their actions to avoid inefficient investment.

2.15 Moreover, the AoB charge has several advantages over an ex ante charge such as an LRMC charge:

(a) it need only be applied after the investment has been made, so parties would only have to pay the charge if the investment was actually made

(b) it relates to the actual Transpower investment that is made and so would be accurate, whereas there is a risk an ex ante LRMC-type charge would provide an inaccurate signal if the investment or its timing changes

(c) it is flexible so can readily be applied to different types of investments including those not motivated by savings from reducing losses and relieving constraints such as some reliability investments

(d) it provides a strong incentive on parties to participate in the investment approval process

(e) it ensures that only those parties that benefit from an investment would pay for it, which makes it more durable

(f) it can readily be applied in combination with other charges, including an LRMC charge, in ways that do not undermine the accuracy of the price signal provided by the AoB charge. This is discussed further below.

2.16 If the conditions in paragraphs 2.10, 2.12 and 2.14 did not hold, then the Authority agrees that there is still a risk of inefficiently early investment. If Transpower considers this to be the case, and it considers that an LRMC charge would be superior to relying on other forms of grid support payments to more efficiently defer grid investment, it could well be possible for Transpower to demonstrate that an LRMC charge contributes to the Authority's statutory objective. Transpower would then be able to propose an LRMC charge, since the proposed guidelines provide for it as an additional component.

2.17 The Authority's approach is also far more efficient than the suggestion of some submitters of a refined regional coincident peak demand (RCPD) charge, because a RCPD charge would provide a price signal that, at best, would only approximate LRMC for some nodes and some time periods, whereas the proposed guidelines provide the potential for a price signal to reflect LRMC.

2.18 The Authority also recognises that introducing a new TPM may increase the risks of unexpected changes in system use, with resulting unintended consequences. The Authority commissioned an analysis from Concept Consulting Group[33] on the impact of its TPM proposal and its distributed generation pricing principles (DGPP) decision on peak electricity demand. The conclusion of the report is as follows:

> "…we expect the most likely outcome of the TPM/DGPP proposals will be to reduce the 2019 WCM [winter capacity margin] by around 270 MW. This results in a WCM of 750MW if all 'high probability' and no 'medium probability' generation plant is built, which is within the economic optimum range..
>
> "However, we note there are some important uncertainties about the incentives applying to certain parties – particularly distributors in relation to ripple control of hot water and some DG [distributed generation] owners. We have therefore considered two alternative 'downside' scenarios. Although we consider these to be less likely, they would result in a larger reduction in the WCM.
>
> "Finally, we note the assessment set out above does not take account of the increase in offered South Island peaking generation capacity following the transmission price changes approved in 2015."[34]

2.19 The proposal appears unlikely to reduce the WCM below efficient levels. There may, however, be more localised areas of system pressure. If Transpower considers that there are some such issues, and it considers an LRMC charge would be superior to relying on other forms of grid support payments to more efficiently defer grid investment, it could propose an LRMC charge in those areas to control system demand while appropriate remedial measures are undertaken.

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33 Concept Consulting Group *Winter capacity margin – potential effect of recent transmission pricing and distributed generation proposals, 2016.*

34 *Ibid.,* section 4.5, page 38.

2.20 Regarding other elements of the proposed charging framework in the second issues paper, the other main issues of contention were:

(a) whether the PDP should be expanded to address the potential for the inefficient exit of parties bearing the incidence of transmission charges: This issue is addressed in chapter 3 below, but it should be noted that most submitters agreed with the proposition that the TPM should include a PDP, but did not consider it should address inefficient exit

(b) whether the residual charge should incorporate a peak signal: Since the framework focuses on the combination of nodal prices plus an AoB charge to promote efficient use and investment, plus incorporates potential for an LRMC charge, the residual charge should be designed to recover remaining revenue in the least distortionary way. Retaining a peak signal through the residual charge therefore would be inefficient.

2.21 Accordingly, the Authority considers that the charging framework set out in the second issues paper is robust and should continue to be the foundation of the Authority's proposal for amending the TPM guidelines.

Refinements to the Authority's proposal would better promote the statutory objective

2.22 As a result of submissions, the Authority has identified refinements to the proposal in the second issues paper that appear likely to better promote the Authority's statutory objective. The refinements that the Authority considers have merit are discussed in chapter 3 of this consultation paper.

2.23 The refinements would:

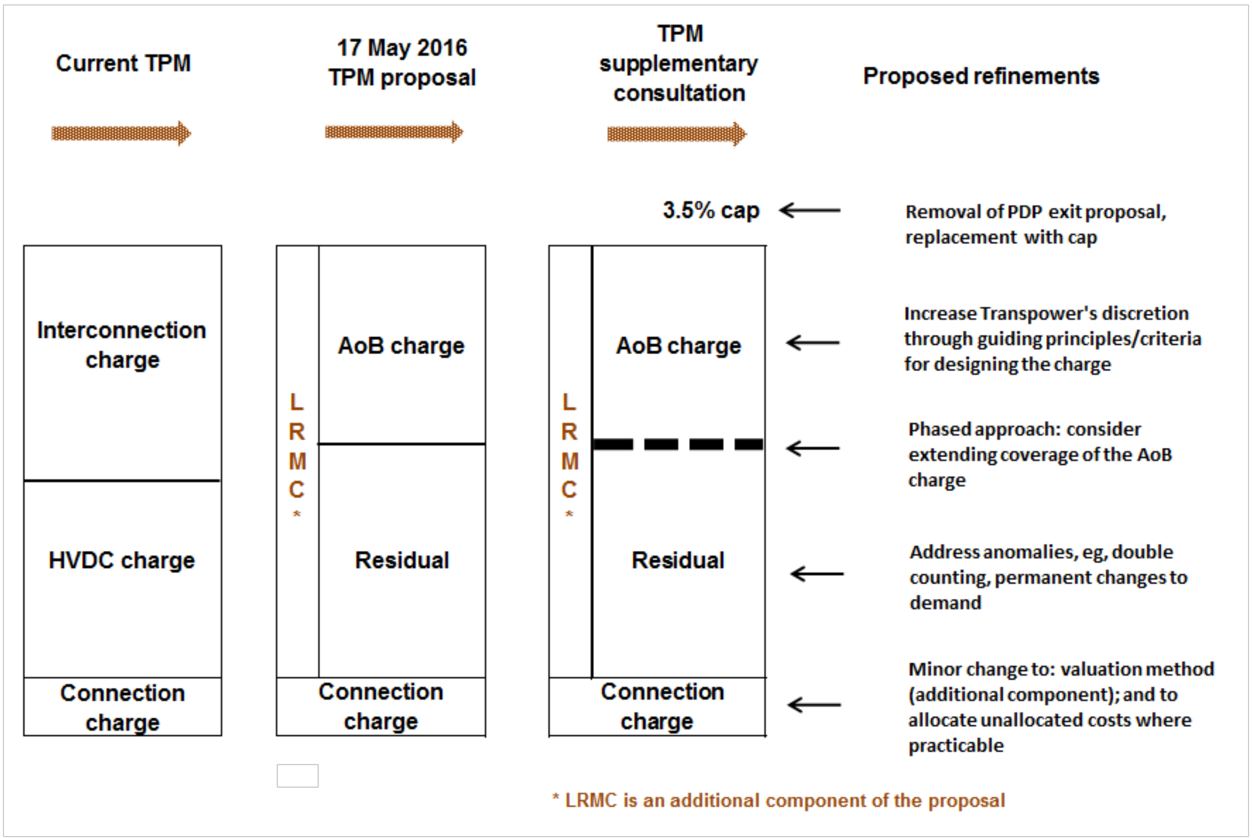
(a) better ensure the proposal provides for service-based and cost-reflective pricing

(b) address some charging anomalies for particular customers, which would improve the durability of the proposal

(c) allocate development of detail to which of the Authority or Transpower is better placed to develop details.

2.24 The following diagram lays out stylised overview of the relationship between the current TPM, the TPM proposed in the second issues paper, and the refinements proposed in this paper.

Figure 4 – The relationships between the current TPM, the proposal as set out in the second issues paper, and the refinements proposed by this paper



The Code requires Transpower to publish indicative charges under a new TPM

2.25 The Authority has provided an update to the indicative charges in the second issues paper reflecting the refinements proposed in this supplementary paper in Appendix F. However, because the proposed refinements give Transpower considerable discretion about how the guidelines are applied in practice, the Authority has had to make assumptions about how Transpower will choose to apply the refinements. If Transpower makes different choices, it could result in the pricing impacts changing significantly from that modelled in Appendix F. The main uncertainties arise from whether Transpower chooses to apply the AoB charge to more historical assets, addressing charging anomalies, and changing the approach to the basis for setting charges.

2.26 In its development of the TPM, Transpower would (as required by the Code) publish indicative charges. Stakeholders would therefore get a more accurate indication of charges before the Authority decides whether to include the TPM in the Code.

Minimum power factor requirement to be addressed separately from TPM review

2.27 The Authority now considers that the proposal to change the power factor requirement in the Code from 1.0 to 0.95 lagging should be progressed separately from the TPM.

2.28 The reason that the power factor requirement has been discussed in the TPM review is because of the inter-relationship between this proposal and the proposal for a kvar charge. While there has been some debate about whether both proposals are needed, submitters appear to accept that a minimum power factor requirement could support a kvar charge and would not duplicate it. Parties also suggested that the current power requirement of 1.0 is impossible to comply with and therefore needs to be changed.

2.29 The Authority agrees that there is now no reason why the minimum power factor proposal needs to continue to be linked with the TPM review and considers that it should be progressed as a separate Code amendment.

2.30 The Authority notes that Meridian and Fonterra agreed with the kvar proposal in the second issues paper. The kvar charge is now an additional component so may or may not be implemented.

3 Proposed refinements to the draft guidelines

Introduction

3.1 This chapter sets out the Authority's proposals for refinements to the draft TPM guidelines. The proposed TPM guidelines are set out in Appendix E, with the changes from the draft guidelines in the second issues paper identified in track change form.

Allowing for a broader coverage of the AoB charge and a transition as an additional component

Proposal

3.2 The proposed guidelines provide that the AoB charge should apply to the eligible investments proposed in the second issues paper at a minimum, and that Transpower must, if doing so would be practicable and consistent with clause 12.89 of the Code, include in the TPM, as an additional component, a method for extending the AoB charge to include other pre-guidelines assets.

3.3 If the additional component described above is included in the TPM, the proposed guidelines provide that the TPM may include a transition. For example, this could be an extension of the cap discussed later in this chapter.

3.4 The proposed guidelines provide that, if the additional component described above is included in the TPM, the TPM must specify a simplified method or methods for calculating the AoB charge for the further assets, if applying the standard method to those assets would not be practicable.

3.5 A simplified method or methods would be used for estimating the private benefits from pre-guidelines investments, other than eligible investments defined in the second issues paper, if Transpower chooses to subject more pre-guideline assets to the AoB charge, and it was not practicable to apply the standard method in relation to those assets.

3.6 The proposed guidelines also clarify that the Authority's intention was to exclude historical non-transmission solutions from the initial list of eligible investments and include only non-transmission solutions arising after the date of the guidelines in the initial list.

Discussion

3.7 The second issues paper proposed that the AoB 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).

3.8 In other words, the second issues paper proposed the AoB charge should be charged for all future investments, including replacement and refurbishment, but only for a select group of historical investments, ie, those identified in paragraph 3.7(b) and (c) above.

3.9 The proposed guidelines clarify that, with respect to paragraph 3.7(d), the intention was to cover only future arrangements with respect to non-transmission solutions.

3.10 The second issues paper proposed this coverage of the AoB charge in relation to historical investments because:

(a) the main benefit identified from applying the AoB charge to historical assets was improved durability, which would lead to improved efficiency, and the benefits from this were greatest for large recent investments and Pole 2

(b) it made the initial application of the AoB charge more practical and limited implementation costs.

3.11 Several submissions suggested that, for the TPM proposal to be service-based and cost-reflective, the AoB charge should be extended to a wider range of historical assets. This was because:

(a) It was more consistent with the DME framework as it involved recovering costs to the extent efficient and practicable on a beneficiaries-pay basis, rather than through the residual charge. The Authority agrees that broader application of the AoB charge would be more consistent with the DME framework, which provides for preference to be given to charging according to beneficiaries-pay rather than alternative charging methods (such as a broad-based low rate charge, the charging approach proposed for the residual charge).[35] This preference holds provided the approach is efficient, practicable to implement, complies with the Authority’s Code Amendment Principles, and covers Transpower's recoverable revenue.

[35] Decision-making and economic framework for transmission pricing methodology: Decisions and reasons, 7 May 2012.

(b) It was consistent with the finding in the sunk cost working paper[36] that infra-marginal decisions are as important for efficiency as marginal decisions.[37] [38] In particular, since it is conceivable that the ownership of some parts of the interconnected grid could be transferred between Transpower and other parties, charging users of those assets their full cost would incentivise efficient ownership decisions (which is an infra-marginal decision, since it involves consideration of more than just the marginal cost of using the asset). NZAS in particular noted that Transpower has an active programme of divesting non-core grid assets, and that applying the AoB charge to those assets would support their divestment where that would be efficient.[39] The Authority agrees that applying the charge to more historical assets would support efficient decisions regarding ownership of and investment in transmission assets, by ensuring that the full cost of an investment is reflected in the charges for it. In contrast, if the cost of an investment is included in the residual and so effectively socialised, a party that benefits from the investment will have little incentive to take it over even if it can manage the asset more efficiently.

(c) It would reduce potential distortions to efficient location of generation and load resulting from applying the AoB charge to only a subset of historical assets.[40] For example, applying the AoB charge to the Wairakei Ring but not to nearby transmission assets provides a disincentive for new generation plant to connect to the Wairakei Ring. This disincentive would be inefficient if the Wairakei Ring has considerable spare capacity.[41] Similarly, applying the AoB charge to only a subset of assets may provide incentives to locate in areas that would be higher cost in the long run, eg, generation distant from load and load distant from generation. The Authority agrees that applying the AoB charge to a wider range of, and potentially all, investments would mitigate these concerns, as it would involve a broader application of a service-based and cost-reflective charge, which would promote more efficient investment decisions.

(d) It would reduce distortions from an excessive residual charge. Applying the AoB charge to more historical assets would result in a greater amount of revenue being collected through the AoB charge and less revenue being collected through the residual. This would lower the rate of the residual charge, which would lower incentives to reduce demand to limit the impact of the residual charge. However, given the proposed design requirements for the residual charge, this would mainly be an issue if distributors chose to pass on the residual charge as a variable charge.

36 Transmission pricing methodology: Sunk costs working paper, 8 October 2013.

37 NZAS submission on the second issues paper.

38 As explained in the sunk costs working paper, a marginal decision is a decision about the last unit (produced) whereas an infra-marginal decision is a decision about all of the units. A decision about investing in a factory to produce a product is an inframarginal decision whereas a decision about how much to produce and sell is a marginal decision.

39 *Ibid.,* page 25.

40 Transpower submission on the second issues paper.

41 This potential efficiency issue is mitigated if connection of new generation plant to either the Wairakei Ring or nearby assets would result in a need for transmission investment. In those circumstances the potential connection of new generation plant would lead to additional AoB charges for the connecting plant.

3.12 The Authority agrees that these reasons suggest there would be merit in considering whether to apply the AoB charge to more historical assets.

3.13 The main costs that need to be considered in extending the AoB charge to more historical assets are:

(a) The costs of calculating benefits and identifying beneficiaries for more historical assets. Transpower would need to consider the costs of calculating benefits and identifying beneficiaries when considering the coverage of the charge.

These costs would depend on the method used for applying the charge. Adopting a simplified method for calculating benefits for these historical assets would facilitate applying the AoB charge to more historical assets. This is discussed later in this chapter.

(b) Potential inefficient behavioural change as a result of recovering the costs of assets from a limited number of customers. Extending the AoB charge to more historical assets could mean the costs of some assets are recovered from fewer customers than if the costs were recovered under the residual. If this resulted in large increases in charges this would increase the incentives on customers to take actions that would avoid them being identified as beneficiaries in order to avoid the charge. However, customers' ability to avoid the charge through behavioural change would be limited through the design of the charge. In particular, charges would to the extent possible be allocated according to expected benefit.[42] Even if a simplified method were used to identify beneficiaries, the behaviour of customers would not affect the allocation of charges except if the behavioural change was so substantial that the threshold was triggered for a "material change in circumstances" review . However, the intention is that this threshold would be set sufficiently high that it would not be triggered except as a result of exceptional changes in demand for services from an asset.

3.14 The proposed guidelines include an additional component that requires Transpower to include in the TPM a method for extending the AoB charge to further pre-guidelines assets if that would be practicable and consistent with the requirements of clause 12.89 of the Code. This would ensure that the costs of broadening the coverage would be effectively managed.

3.15 As a result, the proposal should have net benefits.

3.16 The rationale for allowing Transpower to propose a simplified method or methods for estimating the net benefits from the pre-guideline investments it includes is discussed in the next section.

3.17 If the additional component is included in the TPM, the proposed guidelines provide that Transpower may include a transition in its proposed TPM.

[42] The proposed guidelines provide that where the AoB charge cannot be allocated according to each individual customers' expected benefits the charge would be allocated to load on the same basis as the residual charge (eg, historical capacity, potentially updated with a lag) or average injection (or forecast or lagged historical injection, if the Authority chooses one of those options). This means that it would be difficult for load to alter their charges, while generator incentives to alter their charges would be offset by the stronger incentive they have to be dispatched.

The calculation of benefits will trade off accuracy against practicality

Proposal

3.18 The proposed guidelines provide that[43]

(a) the method for calculating benefits for the AoB charge must be based on expected positive net private benefit

(b) the standard method must be as accurate as is reasonably practicable

(c) in determining the standard and simplified methods, Transpower must weigh the economic benefits of sending accurate price signals against the economic costs of developing and administering the simplified method or the standard method

(d) the TPM must include a simplified method or methods for calculating the AoB charge, to apply to each eligible investment valued at less than $5 million at the time the investment is commissioned or at the completion date, to be applied from the earlier of 3 years after the TPM comes into force, or as soon as reasonably practicable after the standard method has been applied to new investments and pre-guidelines investments valued at more than $5 million.

3.19 If the benefits cannot be realistically estimated using one scenario, the proposed guidelines also provide that Transpower must calculate the benefits under two or more likely scenarios, and calculate benefits based on the average of the benefits under those scenarios.

3.20 The proposed guidelines also provide that Transpower may seek a determination from the Authority as to whether the assumptions it makes in determining the benefits and the resulting estimates of benefits are reasonable, if Transpower considers that averaging benefits under likely scenarios does not result in a robust estimate of benefits.

3.21 Finally, the guidelines remove the requirement that AoB charges to generation and load must be allocated so that each group is allocated charges that correspond to the proportion of aggregate benefits the group is expected to receive.

Discussion

3.22 The second issues paper proposed that the principles for the AoB charge are that:

(a) it should be allocated in accordance with the benefits received by transmission customers

(b) minimal discretion would be a key factor in the design of the methods for determining benefits, so that Transpower's determination of benefits would not be subjective.

3.23 While submitters and international experts differ, the balance of opinion is that robustly estimating benefits could be difficult for new investments, and even more difficult for historical investments, particularly for reasonably old historical investments.[44] Accordingly, in some cases it may be necessary to use some proxy for estimating benefits to ensure an appropriate trade-off between accuracy and practicality. This

43 This is in addition to the requirement proposed in the guidelines in the second issues paper that minimal discretion would be a key factor in the design of the methods for estimating benefits.

44 Transpower submission on the second issues paper.

might be necessary, for example, if a more accurate method is time consuming, expensive, open to judgement, or highly dependent on the input assumptions.

3.24 The Authority continues to be of the view that the principles outlined in paragraph 3.22 are appropriate. However, it is proposed that the way the principles are applied should be clarified and modified in some respects.

3.25 Firstly, the proposed guidelines make it clear that the AoB charge should be allocated according to the private benefit that the parties are expected to receive from the investment, to the extent that it is practicable. This is different from the grid investment test (which the Commerce Commission is responsible for), which considers the total expected net electricity market benefits and not parties' private benefits.

3.26 Secondly, as suggested by some submitters, the guidelines should allow for a simplified method or methods for determining the benefits from the historical investments, if any, that Transpower proposes to include as eligible investments;(ie, investments other than the eligible investments identified in the second issues paper), where the benefits from investments can be more readily determined.[45] This is for the following reasons:

(a) First, it is more difficult to estimate the private benefits associated with historical investments, compared with estimating them for new investments.

(b) Second, the benefits from accurately determining the private benefits from historical investments are less than the benefits from accurately determining them for prospective investments. Essentially, this is because prospective investments can be deferred or avoided, whereas that is clearly not true for historical investments.

(c) Third, it would facilitate the extension of the AoB charge to more historical investments, which is beneficial for the reasons discussed above.

(d) Fourth, calculation of the benefits for older and smaller investments is not as important as for the large recent investments that are eligible investments. This is because calculation of the benefits in relation to these eligible investments using the standard method is likely to result in more durable charges, as the calculation of benefits would be more accurate and therefore less open to dispute.

3.27 For these reasons, it is proposed that a simplified method or methods be permitted for determining benefits, and the allocation of benefits, for historical investments, except for those identified in the second issues paper, as part of the additional component to apply the AoB charge to more historical assets.

3.28 The Authority recognises that it would be appropriate for the method for allocating charges for historical investments to be different from the simplified method for allocating low value investments. This is because the main benefit of a low value investment is likely to be concentrated geographically, whereas that is typically not true of larger historical investments.

3.29 It may be that there continues to be significant uncertainty about Transpower's estimates of benefits. For example, there could be uncertainty about the input assumptions to be used, or about the weighting to give to different scenarios. If Transpower considers it necessary to ensure a robust estimate of benefits, the guidelines require Transpower to model benefits under the most likely scenarios and calculate the benefits based on the

[45] Transpower submission on the second issues paper.

arithmetic average of the benefits under those scenarios. If Transpower considers that doing so has not resulted in a robust estimate of benefits, it may seek a ruling from the Authority about whether its assumptions and the resulting estimates are reasonable.

3.30 Finally, the guidelines remove the requirement that AoB charges to generation and load must be allocated so that each group is allocated charges that correspond to the proportion of aggregate benefits the group is expected to receive. That provision is redundant because the guidelines already provide for charges to be allocated on the basis of positive expected net private benefit and to the area of benefit.

The calculation of net private benefits for the AoB charge to include LCE

Proposal

3.31 The proposed guidelines clarify that in calculating the AoB charge, a customer's net private benefit in relation to an investment is to be calculated taking into account any increase or decrease in the amount of LCE the customer would receive following the commissioning of the investment.

Discussion

3.32 Some submissions expressed concern that the Authority's indicative impact modelling of the AoB charge suggested the charge would not accurately reflect the net private benefits parties received from an investment. For example, Northpower and Top Energy suggested that the modelling of AoB charges for investments that had been undertaken in response to projected growth in Auckland implied an increase in benefits to Northland consumers even though Northland demand was largely unchanged and there was little improvement in the reliability of supply to Northland.[46] The Authority has considered whether further clarification of the calculation of benefits is needed to ensure that AoB charges better reflect expected benefits.

3.33 The LCE on a grid circuit grows as congestion increases.[47] Reducing congestion on a circuit reduces the LCE accruing to the parties that receive LCE. The second issues paper proposed at paragraph 7.317 that the Code be amended to require that LCE from an asset to be allocated to customers that pay charges for that asset. This means that load that stands to benefit from lower nodal prices as a result of a proposed investment would assess whether the benefits from lower nodal prices and a greater volume of electricity transported exceeded the reduction in LCE. Similarly, generation that stands to benefit from higher nodal prices as a result of a proposed investment would assess whether the resulting benefits from higher nodal prices and greater volume of electricity transported exceeded the reduction in LCE.

3.34 Transmission customers would therefore only seek the investment where the net private benefits from changes in electricity prices and volumes exceeded the transmission charges they incurred and the LCE they would otherwise receive if the investment did not proceed. Calculations of net private benefits for determining the AoB charge should reflect this as it would promote efficient investment.

[46] Northpower and Top Energy submissions on the second issues paper.

[47] In particular, congestion would have resulted in greater price separation at upstream and downstream nodes affected by the congestion. This would result in an increase in LCE as LCE arising in relation to a line is the price difference between the relevant nodes multiplied by the volume of electricity transported across the line.

3.35 Consider, for example, an investment undertaken to cater for the growth of one load customer but which would also supply other load customers whose demand is static. The investment would benefit customers whose demand is growing as they would be able to receive increased volumes of electricity as their demand grew. Taking into account LCE prior to and after the investment, they are likely to receive net benefits from it, and therefore be willing to pay for it, because any reduction in LCE resulting from the investment would be more than offset by the benefits they would receive from lower prices and the volume of electricity supplied by the transmission line continuing to meet their demand. For customers with static demand, they may not be so well off from the investment because, even though they would receive lower prices, this may be partly or fully offset by the reduction in LCE that they would receive if the investment was not undertaken. If the calculation of benefits in this example took into account LCE as well as the benefits from lower prices and greater transmission volumes, the AoB charge would be paid relatively more by the party whose load was growing.

3.36 It is therefore proposed that the guidelines clarify that, to the extent possible, calculation of the net private benefits from an investment should take into account any loss of future LCE payments. The indicative impact modelling of the AoB charge in the second issues paper did not take into account the change in LCE in calculating the flow of benefits from investments and therefore in estimating AoB charges. Accordingly, the distribution of modelled charges may have been different from what it would have been if the change in LCE was modelled and included in the calculation of benefits.

The annual AoB charges for an investment to be service-based and cost-reflective

Proposal

3.37 The proposed guidelines provide that Transpower would set the AoB charges for both pre-guideline investments and post-guideline investments so that:

(a) the annual AoB charge for an eligible investment increases over time in line with a price index determined by Transpower

(b) the total AoB charges for an eligible investment recover the full cost of every asset (excluding any connection asset) included in the eligible investment (calculated as if the AoB charge had applied to the eligible investment since it was commissioned or completed), including the capital cost of each asset and an allowance for the weighted average cost of capital for the eligible investment.

The Authority refers to this as the indexed historical cost method for setting charges.

3.38 These two requirements mean that the AoB charges for the investment can be calculated from the actual cost of the investment, an estimate of its expected life, an estimate of operating and maintenance costs over its life and a suitable WACC.

3.39 Transpower may propose in the TPM a method for determining the annual amount to be recovered under the AoB charge that is not based on indexed historical cost, but that is service-based and cost-reflective, if that would better promote the Authority's statutory objective.

3.40 Transpower must choose a method or methods that promotes an efficient trade-off between the economic benefits of sending an accurate price signal to customers versus the costs of developing, implementing and administering the valuation method.

3.41 The proposed guidelines require the TPM to provide for Transpower to alter the time profile of the AoB charge for an investment if the method above would lead to charges that manifestly would not reflect the services provided by the investment at different times in the investment's life.

3.42 The second issues paper proposed to treat the replacement, refurbishment or maintenance of an existing asset that extended its life as a new investment. As noted above, it is now proposed that charges be service-based and cost-reflective. This means that the proposal in the second issues paper in relation to the valuation method that would apply in relation to replacement, refurbishment and maintenance that extends an investment's life is no longer necessary.

Discussion

3.43 The second issues paper was clear that the AoB charge for an investment is intended to recover the forecast capital cost of the investment and the cost of capital on the investment over its useful life, as well as maintenance and operating costs. The Authority is satisfied that this is the appropriate objective.

3.44 With this requirement, the only effect of the valuation base used for the investment is to alter when in an investment's life the bulk of the charges are paid (and so, potentially, who pays them), since the net present value of the charges over its life is fixed.

3.45 The Authority considers that the AoB charges should be service-based and cost-reflective. The second issues paper argued that transmission charges should be based on a cost that reflects "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".[48]

3.46 In other words, in a workably competitive market, a purchaser of utility-type services would be indifferent between the annual services of an old asset and an equivalent new asset, so would not pay more each year for the services of the new asset than for the services of the old one.

3.47 As a result, the inflation-adjusted (ie, real) value of the asset would decline over time mainly because its future service life declines over time, and not because of any change in the annual services it delivers. In other words, the replacement cost of an asset that is part way through its service life is less than the replacement cost of an otherwise identical new asset, simply because it has a shorter remaining service life. The replacement cost of the older asset would simply be the price that an identical asset of the same age could be purchased for in the market, which is the expected net present value of the future cash flows it will generate. So for example, at the start of the final year of its life, the replacement cost of the asset is (approximately) the cash flows it will generate in its final year of life.[49]

48 Second issues paper, paragraph 7.23, page 87.

49 For example, suppose an asset has a value of $100 and a certain service life of 50 years. Suppose the real WACC is 4% (equivalent to, for example, a nominal WACC of 7% and price inflation rate of just under 3%). Maintenance costs are zero. Then the asset's annual aggregate AoB charge is the annual capital cost and cost of capital, which is about $4.70 in the first year and which increases with inflation every year in nominal terms. Half way through its life, the asset's replacement cost is around $70 plus inflation. Its inflation adjusted (real) value has declined because it has a shorter service life.

3.48 In general, the services provided by an investment in the interconnected grid will tend to rise over time as increasing demand increases the amount of power it carries. Offsetting this, the services it provides may fall if demand falls or other complementary assets are commissioned. In other words, the services delivered by a transmission asset are approximately constant in each year of its life.

3.49 As a result, by analogy with a workably competitive market, the total AoB charges for a transmission investment should be set in each year so that they are a constant portion of the replacement cost of an equivalent new investment in that year.

3.50 This is what the Authority intended by its proposal that investments should be valued at their replacement cost. Accordingly, the second issues paper stated that the Authority's preferred valuation method was replacement cost for eligible investments commissioned after the date of the guidelines.

3.51 When combined with the requirement that the total cost of the investment should be recovered over its life, this requirement that the charges be constant in real (ie, inflation adjusted) terms over the asset's life provides sufficient information to calculate the annual AoB charge for the investment.[50]

3.52 If it is necessary for any reason, the replacement cost of a transmission investment that is part way through its life can be estimated as the market value that the transmission investment would have if it were in a workably competitive market. As is noted above, this would be calculated as the net present value of the AoB charges less operating and maintenance cost over the remainder of its life.

3.53 Several submitters suggested that using replacement cost was undesirable because it was complex and contentious.[51]

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50 This may be clarified by a simplified example. Let:

the cost of a transmission investment be *K*

the annual AoB charge in real terms (ie, after adjusting for inflation) in year t be R_t

the real annual operating and maintenance costs in year t be M_t

the life of the investment be *T*

the real WACC be *w*, a constant

Then over its life, the net present value of the total charges collected is given by

$$PV = \sum_{t=1}^{T} (R_t - M_t) * (1 + w)^{-t}$$

For example, suppose that R_t and M_t are constant in real terms (ie, increase only with inflation). Then this equation simplifies to:

$$PV = \left({}^{(R-M)}\!/_{w}\right) * (1 - (1 + w)^{-T})$$

Since the AoB charge must recover the cost of capital and the capital cost over its life, including operating and maintenance costs, this net present value must be just equal to the capital cost of the investment. So knowing the capital cost, and with estimates of *R*, *M*, *w* and *T*, we can use this equation to calculate the AoB charge. It is:

$$R = \left({}^{(w.K)}\!/_{(1 + w)^{-T}} \right) + M$$

This is the method used to calculate the AoB charge in the previous footnote.

51 For example, Meridian submission on the second issues paper.

3.54 Recognising this complexity, the Authority also stated that it was attracted to other methods, including an IHC approach. While less accurate than an RC approach, an IHC approach has the advantage of being a good approximation to a replacement cost approach while being easy to implement. This is because:

(a) as discussed above, the initial charges for a new asset can be calculated from the actual cost of the asset, an estimate of its expected life, an estimate of operating and maintenance costs over its life and a suitable WACC. The Commerce Commission provides estimates of the appropriate WACC (the vanilla median WACC for Transpower), and Transpower is well placed to provide the other data required

(b) subsequent years' charges over its expected life can be determined as the initial charges updated by the price index. The Authority proposes that Transpower would recommend the price index to use to index the charges.

3.55 The Authority's preference is therefore to use an IHC approach to set the AoB charges for new investments. The Authority acknowledges that this is less accurate than a replacement cost approach, because the proxy can deviate from replacement cost over time for a variety of reasons. However, it is likely to yield most of the benefits of using a replacement cost approach while avoiding most of the expense of implementing a true replacement cost approach.[52]

3.56 The second issues paper proposed that investments undertaken prior to publication of the guidelines would be charged on the basis of DHC. Many submitters on the second issues paper argued that pre-guidelines investments should be valued on the same basis as proposed for post-guidelines investments, that is replacement cost,[53] because:

(a) charging on the basis of DHC for recent pre-guidelines investments means that the charges are higher, discouraging the investment's use when it is uncongested, and fall as use of the investment increases

(b) charging on the basis of replacement cost is more service-based

(c) charging on the basis of replacement cost would not involve double charging any customer for any investment, because most of the past charges for any particular investment have been socialised and so have been mostly paid for by the customers who would not in the future be subject to the AoB charge for the investment.

3.57 The Authority agrees that there would be advantages in charging for pre-guidelines investments on the basis of the service they provide, in the same manner as new investments. This would be of greater importance if there was broad coverage of the AoB charge, as provided for in the additional component discussed above. It is proposed that the guidelines would reflect this.

3.58 The Authority accepts the view of some submitters that charging on the basis of replacement cost or an equivalent, such as IHC, does not have the disadvantage of charging any Transpower customer more than once for the same investment. The

52 For example, as noted by Unison, a replacement cost approach would require Transpower to revalue assets every few years. Meridian submitted that a replacement cost asset evaluation is not efficient, is complicated and potentially contentious.

53 Top Energy, Axiom for Transpower, Castalia for Genesis, PowerNet, PwC (for 14 EDBs), Electricity Networks Association (ENA); submissions on the second issues paper. In addition, NZAS, NERA for Meridian and Vector considered there were no clear benefits from using multiple valuation methods.

reason is that those who will have to pay the new AoB charge for a given investment will in the past have paid only a small fraction of the historic cost of the investment, because most of the charges will have been socialised, through the interconnection charge across all users. Thus those who are subject to the AoB charge for a particular investment will pay in total less than the full cost of the investment. Transpower sets out this logic in more detail in its submission.[54]

3.59 The Authority therefore proposes that pre-guideline eligible investments be charged for on the same basis as post-guideline investments, that is, on an IHC basis.

3.60 However, there is complexity in applying an indexed historic cost approach to existing investments that does not apply to new ones. It follows from paragraph 3.47 that in the absence of an effective market for second hand transmission assets, the only way of estimating the replacement cost of an existing asset is by calculating the present value of its remaining cash flows. That requires an estimate of the AoB charges for the investment.

3.61 However, the AoB charges for an existing asset can be estimated in the same manner as for a new asset, if the charges are calculated over the entire life of the asset from the time it was new.[55] They can then be indexed forward in the same manner as for a new asset.

3.62 Consequently, the Authority proposes that Transpower sets all AoB charges using an indexed historical cost valuation method.

3.63 However, Transpower may propose a different method that is, or methods that are, service-based and cost-reflective for setting the AoB charges if that would better promote the Authority's statutory objective.

3.64 As outlined above, the implicit assumption in using an approach like IHC is that the flow of services delivered by the asset is approximately constant in real terms (ie, after adjusting for inflation). As a rule that should be a reasonable assumption. However, there may be circumstances where it is not. For example, it may be that the investment is larger than current needs require in order to cater for a known future step-change in demand. In that case, imposing a constant annual inflation-adjusted charge could lead to excessive charges early in the investment's life. One example would be where Transpower knows that several customers will use a new investment, but only one connects immediately. Another example would be where a second investment has to be built before the first investment can be fully utilised.

3.65 To cater for circumstances like these, it is proposed that the guidelines give Transpower the discretion to alter the time profile of the charges to better reflect changes in the services provided by the investment over time where the standard valuation method would lead to charges that manifestly would not reflect the services provided by the investment at different times in the life of the investment. The requirement to recover the cost of the investment including its capital, maintenance and operating costs over its life would remain.

3.66 The second issues paper proposed that if Transpower undertook replacement, refurbishment or maintenance expenditure that is expected to extend the life of an asset

54 Transpower submission on the second issues paper, Appendix E.

55 In fact, the charges are likely to be more accurate, because it is likely to be easier to estimate the asset's remaining useful life, and so its total life.

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.

3.67 The Authority is now of the view that this is not service-based and cost-reflective, because it would result in the total annual AoB charges for the updated asset changing over time. This is because the updating of the asset in effect creates a new asset. For the reasons discussed earlier, it can be expected that this updated transmission asset will provide roughly the same level of services in each year of its newly extended life, and so the annual charge for access to the asset should be constant after adjusting for inflation. Accordingly, it will normally be appropriate to use the method or methods proposed by Transpower described in this section to update the charges for the investment.

The residual charge, the charges for overheads and unallocated costs, and AoB charges for pre-guideline investments may need adjustment

Proposal

3.68 The proposed guidelines provide that the charges for pre-guidelines investments[56] be set in the same way as for post-guidelines investments, provided that this approach is practicable and does not result in the over-recovery of Transpower's recoverable revenue.

3.69 To deal with situations where it is impracticable for Transpower to establish the amount to be recovered under the AoB charge in relation to the cost of a pre-guidelines eligible investment, the guidelines would provide that Transpower could use a suitable proxy.

3.70 If the method for determining the annual amount to be recovered under the AoB charge in relation to pre-guideline investments would result in over-recovery of Transpower's recoverable revenue, the proposed guidelines provide that the TPM must provide for a method to scale back transmission charges.

3.71 The proposed guidelines propose scaling back:

(a) the residual charge (excluding overheads and unallocated costs), then

(b) to the extent that the over-recovery remains unresolved, the charges for overheads and unallocated expenses, then

(c) to the extent that the over-recovery remains unresolved, the AoB charge for pre-guideline investments.

Discussion

3.72 As is noted above, the proposed guidelines provide that the charges for pre-guidelines investments be set following the same principles as for post-guidelines investments.

3.73 However, setting AoB charges for pre-guideline investments following the same principles as for post-guideline investments may not be practical. Transpower estimates the replacement cost of its assets, excluding easements, to be more than twice its RAB.

56 An asset-based valuation rather than an investmen- based valuation may be the appropriate charging basis for historical investments, since it may be difficult to determine what the original investments were.

For old assets in particular the indexed historic cost (and the replacement cost) might be much larger than their depreciated historic cost. As a result, there is a risk that, if the AoB charge for historic assets is set in the manner proposed, the total charges under the TPM could recover more than Transpower's recoverable revenue. Furthermore, if grid investment slows down, the chances of this happening would increase.

3.74 This result would be in part an artefact of Transpower being able to recover its revenue according to DHC, which means that, compared with a replacement cost or similar approach, the recovery of the capital cost of historic assets has been front-loaded. It may also be a result of:

(a) the service life of some assets (or some parts of some assets) being underestimated, and/or

(b) Transpower having been able to treat what are in economic terms capital improvements (and so should in economic terms have been capitalised) as maintenance (and so has been expensed).

3.75 All of these issues would result in Transpower charging on a basis that entails recovering the cost of the asset more quickly than under a service-based approach, and so result in charges that implied the true economic value of the asset[57] would be greater than the value recorded for the asset in Transpower's books.[58]

3.76 It is proposed above that the charging basis for historical assets should be the same as for new assets, ie, follow the proposed requirements in paragraphs 3.37 – 3.42.

3.77 Transpower has indicated that it may not have information on the historical cost of its older transmission investments. If Transpower cannot determine the original historical cost of a pre-guidelines eligible investment, it would not be able to calculate the AoB charge for the asset, because it could not apply the method described in paragraphs 3.60 and 3.61 in relation to the eligible investment. So to deal with situations where it is impracticable for Transpower to establish the amount to be recovered under the AoB charge in relation to the cost of a pre-guideline investment, the guidelines would provide that, Transpower could use a suitable proxy.

3.78 If the effect of the charging basis would be that, without scaling, total charges under the TPM exceed Transpower's recoverable revenue, Transpower would need to identify a method for ensuring that charges did not exceed its recoverable revenue.

3.79 The Authority proposes that if necessary the residual charge (apart from that part used to recover overhead and unallocated costs) be reduced to ensure that Transpower's total charges do not exceed recoverable revenue. The reason that it is best to reduce the residual is that the AoB charge, and particularly the AoB charge on new investments, would promote efficiency.

3.80 To the extent that the over-recovery remains unresolved, then it is proposed that charges to recover overhead and unallocated operating costs be scaled back.

57 That is, what the market value would be if the market were workably competitive, as discussed under the heading "The total annual AoB charges for an investment should be service-based and cost-reflective" above.

58 This does not imply that the value of the assets for determining Transpower's recoverable revenue is in any sense wrong. As an asset owner, Transpower is concerned with getting a fair return over the asset's life, and this can be achieved under any valuation method.

3.81 To the extent that the over-recovery still remains unresolved, then it is proposed that the amount recovered by the AoB charge in relation to pre-guidelines eligible investments be scaled back. In relation to the scaling back of the amount recovered by the AoB charge in relation to pre-guidelines investments, this is the Authority's proposal, but the Authority has also considered two potential ways this could be achieved in practice. These are

(a) scaling back proportionately the AoB charges for pre-guidelines investments

(b) disproportionately scaling back charges for pre-guideline core grid investments relative to non-core grid investments.

3.82 These options are discussed in turn below. It is proposed that Transpower propose a method of reducing the charges which best meets the requirements of clause 12.89 of the Code.

(a) Scaling the AoB charges for pre-guidelines investments

3.83 If without scaling, total charges under the TPM exceed Transpower's recoverable revenue, Transpower could reduce the AoB charge pro-rata for pre-guideline investments. This would therefore preserve the relativity between the AoB charges in different locations.

(b) Disproportionately scaling back the AoB charges for historical core grid assets

3.84 An alternative approach to ensuring total TPM charges did not exceed Transpower's recoverable revenue would be to disproportionately scale back the AoB charges for those pre-guideline assets that are part of the core grid. This would have the advantage of limiting the scaling back of the charges for non-core grid assets (such as the 110kV network) for which individual ownership contestability is most practicable. This would improve the incentives for efficient ownership decisions about these assets. The main disadvantage of this option is that there would be different charges for core and non-core grid assets, which would be inconsistent with service-based and cost-reflective charging. Further, it would distort locational decisions by providing incentives for generation and load to locate away from the non-core grid.

Optimisation available only for high value investments

Proposal

3.85 The proposed guidelines clarify that if Transpower proposes to apply the AoB charge to additional pre-guideline investments, then optimisation would be available on the same basis as the eligible investments identified in the second issues paper, that is, for assets in high value investments but not low value investments.

Discussion

3.86 The logic for this proposal is the same as the logic applying to the analogous proposal for the eligible investments discussed in the second issues paper.

Should the fall-back method for allocating the AoB charge to generation be lagged or forecast injection?

Proposal

3.87 The fall-back method for allocating the AoB charge to generation is average injection. This is still the Authority's preferred option. However the Authority is open to using another method, such as lagged or forecast injection. It is therefore seeking feedback on whether it would be preferable to use another allocator for generation instead of average injection.

Discussion

3.88 NERA for Meridian has suggested that the fall-back method for allocating the AoB charge to generation could be on the basis of forecast average injection.[59] It suggested that this would be fixed and less distortionary.

3.89 The current proposal, average injection, is in effect a tax on average injection, which may inefficiently discourage injection. Using either forecast injection or lagged historical injection (analogously to lagged historical gross capacity that the second issues paper proposed to be used to calculate the residual charge) could reduce this disincentive. At the same time it may create other distortions. In addition, how beneficial it might be would depend on how often the fall-back method needs to be used in practice.

3.90 The Authority is seeking feedback on what would be the best method to use.

An additional component to align the method for charging for connection assets with the method for charging for AoB assets

Proposal

3.91 The proposed guidelines provide for an additional component to be included in the TPM that would align the method for determining the annual amount to be recovered in connection charges in relation to each connection asset with the method for AoB assets, if that would be practicable and consistent with the requirements of clause 12.89 of the Code.

Discussion

3.92 The second issues paper noted that there was a potential boundary problem between the treatment of connection assets and AoB assets. Specifically, it stated that "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 average historic cost (AHC) basis".[60] It suggested that one way to avoid this problem was to "require Transpower to value new connection assets on the same basis as new non-connection assets. This approach would eliminate the potential boundary problem, and it would increasingly convert connection charges to a fully service-based approach".[61]

3.93 It is proposed above that the proposed guidelines provide for setting the AoB charge for eligible investments using an indexed historical cost approach, and that Transpower could propose another approach if this would better promote the statutory objective. To address the potential boundary problems discussed in the previous paragraph, the Authority proposes that the guidelines provide an additional component that allows Transpower to align the method for determining the annual amount to be recovered in connection charges in relation to each connection asset with the corresponding method

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59 NERA report, Meridian submission on the second issues paper.

60 Second issues paper, paragraph 7.148(b).

61 Second issues paper, paragraph 7.152(a).

for AoB assets, if that would be practicable and consistent with the requirements of clause 12.89 of the Code.

The marginal price adjustment for a new investment to be an additional component

Proposal

3.94 The proposed guidelines provide that the marginal price adjustment for the AoB charge would be an additional component. It has also been amended so that charges would be adjusted only if the reduction in demand committed to by the customer would result in a decrease in Transpower's costs.

Discussion

3.95 The second issues paper proposed that, when a transmission customer altered its demand for transmission services in response to an investment proposal by Transpower, its AoB charge should be adjusted by the actual saving or increase (if any) in investment costs that Transpower gained as a result of that change in demand.

3.96 Submitters had mixed views about the benefit of this policy. Some thought it would increase the efficiency of the AoB charge.[62] Others thought it would be complex and difficult to implement or even unworkable.[63] In addition, at one of the workshops following the release of the second issues paper, it was argued that the proposal could encourage Transpower's customers to inefficiently alter their behaviour so as to benefit from a (more beneficial) average cost saving rather than the proposed marginal cost saving. If this occurred in practice, this would undermine the efficiency gains from including this element in the AoB charge.

3.97 Given the risks of inefficient behaviour as a result of the inclusion of this element in the AoB charge, and also the doubts about the extent it would be used in practice, the Authority considers that it would be better to include the marginal price adjustment component as an additional component. The Authority therefore proposes that the guidelines provide for the marginal price adjustment element to be an additional component which Transpower must include in the TPM if doing so is practicable and consistent with the requirements of clause 12.89 of the Code.

3.98 The Authority had originally proposed that the marginal price adjustment would apply when a customer increased or decreased its need for services. However, there is a difficulty with applying it when a customer's actions lead to increases in Transpower's costs. The difficulty is that it provides an incentive for a customer to conceal its expansion plans from Transpower until after Transpower has published its investment proposal, so that the customer benefits from a marginal cost adjustment rather than an average cost adjustment. It is therefore proposed to restrict any implementation of the proposal to downward cost adjustments only.

62 Meridian submission on the second issues paper.

63 Transpower submission on the second issues paper.

Transpower must seek to make a more specific allocation to the connection and AoB charges of overhead and unallocated expenses

Proposal

3.99 The proposed guidelines provide that to the extent practicable, Transpower must seek to allocate expenses currently classified as overhead and unallocated expenses to the connection asset or eligible investment to which the expenses relate.

Discussion

3.100 The second issues paper proposed that the guidelines would require that Transpower's overhead and unallocated operating expenses should be recovered:

(a) from generation designated transmission customers, through the connection charge

(b) from load designated transmission customers, through the residual charge.

3.101 In addition, the guidelines proposed in the second issues paper specified that 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.

3.102 The second issues paper also discussed the option of recovering overhead and unallocated operating expenses on the basis of a surcharge to connection, AoB and residual charges.

3.103 Submitters held a range of views as to the treatment of overhead and unallocated operating expenses. While some agreed with the proposed approach[64] others considered that a surcharge approach would be preferable on the basis that common costs are nevertheless a cost of production and would be recovered through prices by a firm operating in a workably competitive market.[65] The Authority agrees that a workably competitive market provides the appropriate benchmark. However, it considers that since the costs cannot be attributed to any one customer, a firm in a workably competitive market would seek to recover common costs from charges to those customers whose behaviour would be least affected by the charges. The Authority's view is that this is best achieved by recovering the costs through the residual.

3.104 However, the Authority also agrees with other submitters who suggested that an effort should be made to attribute costs to beneficiaries wherever possible, and that where this could be done these costs should be recovered through the AoB charge.[66]

3.105 Accordingly, the proposed guidelines now provide for Transpower to seek to allocate costs currently classified as overhead and unallocated costs to the connection asset or eligible investment to which they relate to the extent that it is practicable to do so. The level of unallocated operating expenses and overhead currently amount to about $198 million per annum. The intention of this proposal would be to reduce the level of unallocated operating expenses and overhead so that it represents, as much as practicable, only true common costs.[67] These would be recovered through the residual

[64] For example, Meridian and Nova Energy submissions on the second issues paper.

[65] For example, NZAS submission on the second issues paper.

[66] For example, Oji Fibre and NZAS submissions on the second issues paper.

[67] That is, costs that would be incurred irrespective of a particular project.

charge for load and through the connection charge for generation. Recovering what is now categorised as unallocated operating expenses and overhead from beneficiaries to the extent practicable would better ensure that the AoB charge was more service-based and cost-reflective, and so better promote efficient use and investment. It would also keep the residual in particular smaller, and so reduce distortions from this charge.

The load of each customer is to be used to identify who is liable for the residual

Proposal

3.106 The proposed guidelines provide that the load of each customer is to be used to identify who is liable for the residual charge and the extent to which those customers must pay.

Discussion

3.107 Under the guidelines proposed in the second issues paper, the residual would be charged to load (using a proxy for capacity) but not to generation. Although the calculation of the residual charge was based on historical load and DG and DR, updated with a lag, a load customer could have an incentive to invest in inefficient DG to become a net generator and so avoid the residual charge over the long-term.

3.108 In addition there is a boundary issue. A customer can be a net load at some times in a year and a net generator at other times. This raises the prospect of having to allocate to such customers a proportion of the residual depending on the extent to which they are load.

3.109 To avoid these issues, it is now proposed that the guidelines provide that all customers be subject to the residual charge if they have a positive load, whether they are a net generator or a net load (ie, whether their generation exceeds their load or vice versa).

3.110 This would mean that in principle both load and generators would be subject to the residual. For a customer whose main business is generation and whose load is a necessary part of its generation activities, the residual charge would be small but may not be zero. This approach would have much the same effect as that previously proposed while avoiding the problems that arise from distinguishing between load and generation.

The calculation of the residual charge, and if necessary the AoB charge for load, must follow principles and be less prescriptive

Proposal

3.111 The proposed guidelines provide that the residual charge should be calculated according to historical AMD or another method. The chosen method must:

(a) to the extent that it can be economically achieved, be designed to ensure that the quantum of residual charge that load is charged cannot change either as a consequence of its own actions or the actions of any other party (except Transpower), such that it does not create incentives or opportunities for designated transmission customers to inefficiently avoid the residual charge

(b) be related to the size of the load of the transmission customer, so that its allocation is durable.

(c) be designed so that any DG that is paid or credited for transmission charges avoided by the relevant distributor would not receive such payment or credit in respect of the residual charge component of the relevant distributor's transmission charges (for example, by adding back a value representing the load supplied by the DG for the purpose of calculating the residual charge)

3.112 The proposed guidelines no longer specify that line or transformer capacity be used as the basis for allocation of the residual charge.

Discussion

3.113 The second issues paper proposed that the residual charge would be applied to load and allocated according to the share of physical capacity. The paper proposed that physical capacity would be calculated as follows:

(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 AMD in the 5 years prior to 17 May 2016.

3.114 Many submitters opposed the use of line or transformer capacity as the basis for allocation of the residual charge (and if necessary the AoB charge), on the basis that it is a poor measure of the transmission capacity that the customer actually needs.[68] For example, Waipa Networks noted the following examples of cases in which using transformer or line capacity would be excessive: Powerco's Moturoa zone substation (high physical capacity due to former New Plymouth power station) and Transpower's Carrington Street grid exit point (GXP) which has a high physical capacity due to previous generation capacity at New Plymouth and historical grid planning decisions.[69]

3.115 Further, some submitters considered that the specification of the capacity measure is too prescriptive, and that it would be better to specify the principles that the capacity measure must meet, and leave Transpower to propose the precise capacity measure.[70]

3.116 The Authority agrees that not prescribing a particular capacity measurement approach, and providing for Transpower to propose an approach to the Authority according to a set of principles, has merit.

3.117 Some submitters also considered that the capacity basis for the residual charge (and, if applicable, the AoB charge) should not be grossed up for DG and DR (ie the residual should be based on net load at a GXP).[71] This was on the basis that charging customers for capacity that they do not have and do not need, would be perceived as unfair, would affect durability.

3.118 Further, to the extent that the residual charge affects behaviour, some submissions suggested that grossing up AMD would amount to a tax on new DG and DR, discouraging its use to efficiently substitute for new transmission investment.[72] The Authority does not accept this argument. If, for example, an investor builds DG, it does not reduce the customer's gross load because the calculation of gross load adds back any DG generation. For example, if a customer without DG builds DG (or a third party

[68] For example, EA Networks submission on the second issues paper.

[69] Waipa Networks submission on the second issues paper.

[70] For example, Unison submission on the second issues paper.

[71] For example, Top Energy submission on the second issues paper.

[72] For example, Axiom report, Transpower submission on the second issues paper.

builds DG) under the proposal the customer's residual charge would not change because, although its net load would reduce, calculating their gross load involves adding the DG to the customer's net load, which is the same as the customer's net and gross load if the DG had not been built. As a result, the building of DG would not affect the customer's residual charge, and so the residual charge has no effect on the incentive to build DG.

3.119 The Authority has considered how to ensure that using gross AMD to allocate the residual does not penalise significant changes in demand or recent investment in DG or DR, but without artificially encouraging investment in or use of DG or DR. DG and DR are important substitutes for transmission. Where they are lower cost than transmission investment, it would be efficient to encourage their operation and investment if nodal prices fail to provide efficient incentives. This is to ensure that price signals encourage DG and DR where that is efficient to avoid or defer transmission investment. However, the capacity measure would need to ensure that the allocation of the residual is not affected to ensure that the residual charge does not provide incentives for inefficient investment in or operation of DG or DR. In particular, it would need to ensure that if DG operates, it does not reduce a customer's residual charge.

3.120 One approach would be to allocate the residual charge according to "adjusted AMD". Adjusted AMD would be the highest (net) AMD in the last ten measurement years prior to the date of the release of the revised draft guidelines that are the subject of this consultation, but an adjustment would be made under the following circumstances:

(a) If the annual AMD in any measurement year subsequent to the year with the highest annual AMD but prior to the release of the guidelines was lower than the highest AMD over the last ten years by more than 10 percent

or

(b) If Transpower's forecast of annual AMD (using information publicly available on the date of the release of the revised draft guidelines) in any of the next five years is lower than the highest AMD in the last ten years by more than 10 percent, and this is as a result of changes in demand, DG and/or generation capacity announced prior to the date of the release of the revised draft guidelines

and

(c) Transpower considers that it would have been, or would be, economically efficient to install reduced capacity at the connection point to cater for this reduced AMD if it would have done this given existing assets (and so is a greenfields decision).

In these cases, adjusted AMD would be the maximum annual AMD that could be supplied by the capacity Transpower considers would be efficient to install.

3.121 This approach means that, unless recent DG (ie, commissioned within the last 10 years) would have reduced actual transmission capacity requirements at a grid connection point there is unlikely to be any material difference between adjusted AMD and gross AMD. The approach does, however, mean customers are not penalised because of material changes in demand etc that have happened or are forecast to happen on the basis of information prior to the release of the policy, provided they would reduce capacity requirements.

3.122 As was proposed for gross AMD in the second issues paper, this measure could be adjusted on a lagged basis to keep it relatively current.

3.123 The Authority considers that the principles of an efficient residual (and, if need be, AoB) allocator are that:

(a) to the extent that it can be economically achieved, it is designed to ensure that the quantum of residual charge that load is charged cannot change either as a consequence of its own actions or the actions of any other party (except Transpower), so that it does not create incentives or opportunities for designated transmission customers to inefficiently avoid the residual charge

(b) it is designed so that any DG that is paid or credited for transmission charges avoided by the relevant distributor would not receive such payment or credit in respect of the residual charge component of the relevant distributor's transmission charges (for example, by adding back a value representing the load supplied by the DG for the purpose of calculating the residual charge)

(c) it is related to the size of the load of the transmission customer, so that its allocation is durable

(d) it results in broadly equivalent charges to customers that are in broadly equivalent circumstances.

3.124 Provided these requirements are met, the Authority considers that there is little reason to favour one allocator over another except to the extent that a particular option better promotes the Authority's statutory objective. The Authority therefore is of the view that the proposed guidelines should allow Transpower to choose historical AMD or another method. For example, Transpower could choose historical gross AMD with a lagged update, adjusted AMD, or another method that meets the above principles.

Calculation of the residual to avoid double counting and other anomalies

Proposal

3.125 The proposed guidelines provide that calculation of the residual charge must:

(a) seek to avoid double counting and other charging anomalies

(b) result in broadly equivalent charges to customers that are in broadly equivalent circumstances.

Discussion

3.126 Several submitters on the second issues paper pointed out that the configuration of the transmission assets proposed to be used for calculating the residual charge appeared to inflate their charges relative to other customers. Examples include:

(a) Reefton, where two separate grid exit points (GXPs) have been set up for the one site because the relevant lines into these GXPs lines have different loss characteristics[73]

(b) Orowaiti, where the network configuration means there are two GXPs but this means measuring AMD at each GXP would result in double counting[74]

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73 Westpower submission on the second issues paper.

74 Buller submission on the second issues paper.

(c) Electricity Ashburton, which is transitioning from a 33kV network to a 66kV network and so has two nodes at present but would have one in the future.[75]

3.127 Another apparent issue is that the proposed period for calculating AMD (which the second issues paper proposed to be 5 years prior to release of that paper) does not take into account significant changes in some customers' demand, such as the departure of a major load, eg, the closure of the Holcim cement works in Westport (Buller Electricity).

3.128 These issues could also arise in relation to the AoB charge if it is calculated on the same basis as the residual for load because an allocation of charges based on benefit is not possible.

3.129 The intent of the policy proposal was that customers that have similar characteristics would be treated in the same manner. Allowing the anomalies to persist is likely to affect the perceived fairness of the regime and so impact on its durability. It may lead to some charges being above stand-alone cost, which would be inefficient. It may also induce inefficient behaviour (eg, it has been suggested to the Authority that some networks could connect to adjacent networks in order to receive a lower residual charge[76]).

3.130 It is therefore proposed that the guidelines require that the method for calculating the residual charge provide for correcting for double counting and other charging anomalies. To clarify the intention of addressing charging anomalies, it is proposed the guidelines also require that the method for calculating the residual charge must result in broadly equivalent charges to customers that are in broadly equivalent circumstances.

Modelling of the impacts of addressing anomalies

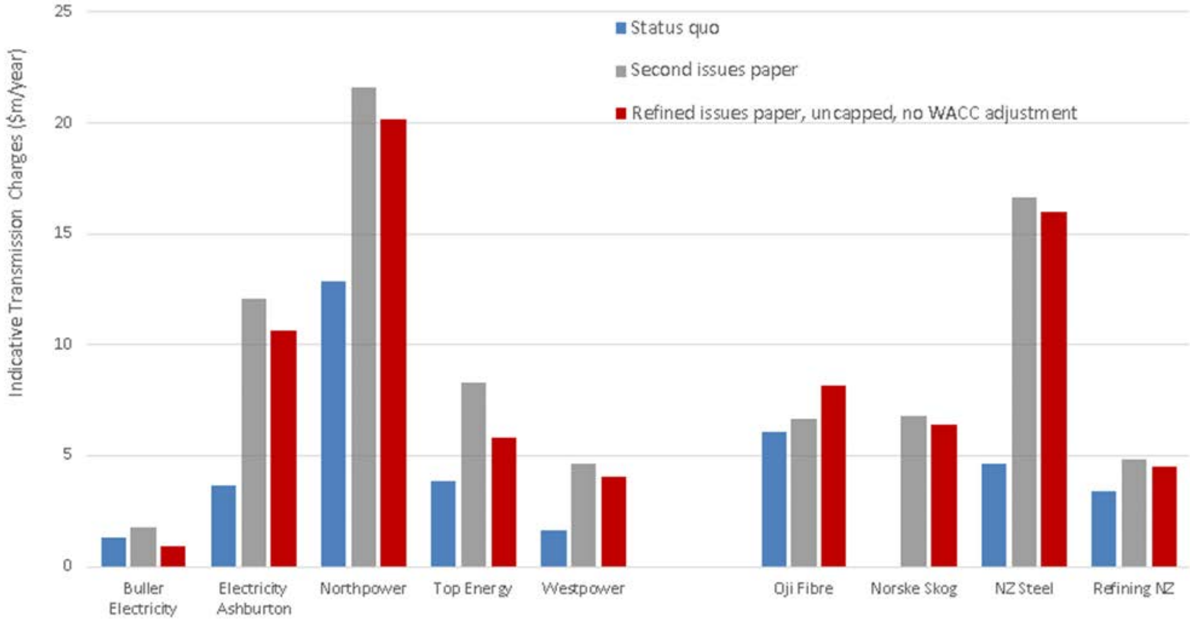
3.131 The Authority has modelled the impact of addressing the anomalies it identified.

3.132 The figure below illustrates the indicative impact of addressing the anomalies identified by the Authority. The modelling is indicative because, in practice, Transpower would be responsible for adjusting charges for anomalies.

75 EA Networks submission on the second issues paper.

76 Where it is economically viable for a party to do this, they would potentially be eligible for a prudent discount.

Figure 5 – Indicative charges in $m/year from addressing anomalies



3.133 Electricity Ashburton, Buller and Westpower residual charges have been adjusted downwards to reflect the aggregation of some loads, and in relation to Buller and Westpower, their residuals were adjusted downwards to accommodate permanent reductions in demand.

3.134 NZ Steel's revised indicative charges reflect a modified approach which involved netting generation from the Alinta-owned co-generator at Glenbrook against NZ Steel's offtake for the purposes of calculating the residual charge. In the second issues paper, the modelling assumed netting between industrial customers and their co-generation plants, but only where the co-generation plant was owned by the relevant industrial customer.

3.135 NZ Steel's charges have also been adjusted to reflect the inclusion of Pacific Steel's charges into NZ Steel's charges, and the de-rating of load at Mangere (MNG). A further adjustment has been made to improve modelling of demand response at NZ Steel's Glenbrook (GLN) site.

3.136 The indicative charges for Oji Fibre (previously shown as Carter Holt Harvey) have increased relative to the second issues paper because the modelling of industrial consumers' charges involved a revised approach for netting industrial customers' offtake against their onsite generation. In the modelling included with the second issues paper, and in the absence of robust data, the Authority subtracted 35MW of onsite geothermal generation to calculate Oji Fibre's net demand. In its revised approach, the Authority used offered generation which caused a change to Oji Fibre's AMD. Ultimately, this highlights the sensitivity of AMD numbers to onsite generation.

3.137 Top Energy's indicative charges reduce mainly due to the effect of de-rating of Mangere and the effect of an additional 25 MW of generation at Ngawha (modelled as a 25 MW reduction in demand). This later adjustment also caused NZ Steel's, Northpower's and NZ Refinery's indicative charges to reduce.

The AoB and residual charge of a large consumer to be tied to the consumer

Proposal

3.138 If a large consumer chose to shift its supplier from Transpower or a distributor to another supplier (whether Transpower or another distributor), the AoB and residual charges it paid to the original supplier would shift with it and:

(a) in the case of a shift to a distributor, become an additional liability of the new distributor

(b) in the case of a shift to Transpower be payable to Transpower by the large consumer.

3.139 If the original supplier was a distributor, its AoB and residual charges would be correspondingly reduced. If the large customer shifted its supply from Transpower to a distributor, the large customer would no longer pay transmission charges.

3.140 For the purpose of this proposal, the guidelines provide that if the large customer shifts its supplier at any time after the date of release of this supplementary paper but before the date of implementation of the new TPM the shift is deemed to occur on the date the new TPM comes into force.

Discussion

3.141 If a large consumer of electricity shifts to another supplier, the shift would likely be considered a material change in circumstances. This would trigger a recalculation of AoB charges so that the AoB charges would tend to move with the consumer.

3.142 The same is not true for the residual charge. The residual charge therefore provides an unintended price signal for the large electricity consumers to alter their supplier to avoid or reduce their residual charge. This would be inefficient.

3.143 However, the proposed refinement covers both AoB charges and residual charges, to provide for situations in which the shift is not considered to be a material change in circumstances.

3.144 This is not a significant issue for a small customer, since the cost of changing supplier is unlikely to be worth the savings in the residual charge and (potentially) the AoB charge.

3.145 It is therefore proposed that if a large consumer changes supplier, the consumer's residual charge should move with it and (if the supplier is a Transpower customer) the charges would also be added to the customer's residual charge.

3.146 It is also proposed that the AoB charge shift in the same manner as the residual charge both for consistency and to avoid an unnecessary change in circumstance review.

If an LRMC charge is applied, the TPM must specify a method to adjust other charges

Proposal

3.147 The proposed guidelines provide that if an LRMC charge is included in the TPM, the TPM must specify a method to adjust transmission charges to take into account revenue recovered by the LRMC charge. (This is the Authority's current preference but it is considering whether it should be more specific about the nature of the adjustments required).

3.148 The proposed guidelines provide that:

(a) the LRMC charge must complement or augment, but not duplicate, price signals provided by nodal pricing, other transmission charges, and any grid support arrangements relied on by Transpower to efficiently defer transmission investment

(b) an LRMC charge may only be included if a price signal is required, over and above the price signals provided by nodal pricing, other transmission charges and any grid support arrangements relied on by Transpower to efficiently defer transmission investment.

Discussion

3.149 The second issues paper allowed for the introduction of an LRMC charge. This would be applied if nodal pricing is insufficient to efficiently limit grid use and if it is at least as good as using other forms of grid support arrangements to limit grid use. It also proposed that revenue recovered through the LRMC charge would be used to offset the residual charge. This was on the basis that it would reduce the economic distortions arising from the residual charge. The design of the residual charge means that this adjustment would happen automatically.

3.150 Transpower submitted that it would be more appropriate to adjust the AoB charge in the first instance to ensure that the combination of the LRMC charge and the AoB charge did not over-signal future transmission costs.[77] This was because LRMC charges would be calculated according to the costs of future transmission investment, while the AoB charge would be used to recover the cost of an investment once it had occurred. Its view is that this combination of an LRMC charge and an AoB charge raises the risk of double charging, and over-signalling future transmission costs, unless one or the other is adjusted.

3.151 Some submitters argued that an LRMC charge is needed to avoid a "tragedy of the commons" situation which would lead to inefficiently early investment. The Authority agrees with these submitters that some price signal is necessary to coordinate users' actions and so prevent inefficiently early investment. The Authority considers that an LRMC charge is most likely to be needed to ration use of the *existing* grid to efficiently defer new investment when, for some reason, nodal prices are not sufficient to do so and the LRMC is at least as good as other possible grid support arrangements in limiting grid use until investment is efficient.

3.152 The Authority sees the LRMC charge not as a forward looking price for future investment (even if it is calculated on the basis of the cost of future investment) but as a price that reflects the opportunity cost of the current use of a scarce resource – the existing grid. The user who benefits from the grid pays the LRMC charge not because future investment is required but because the opportunity cost of their use of the existing grid is the cost of denying another user the use of the existing grid.

3.153 This reasoning can be illustrated by a simplified example. Suppose that an existing line is becoming congested but that it is known with certainty that use of the line will never increase to the point where it is economically efficient to expand capacity on the line. Suppose for some reason nodal pricing does not apply to the line. Then a kWh charge (in the form of an LRMC charge) is necessary to limit use of the line to its capacity and so avoid the need to (inefficiently) expand its capacity. But it is not a forward looking

77 Transpower submission on the second issues paper.

charge for expanded capacity, because by assumption, the expanded capacity is never needed.

3.154 Another hypothetical way of illustrating the same point is to assume that the line is congested in period 1 and its capacity is expanded for period 2. Assume that user A uses the line in period 1 but not period 2, while user B will use the line in period 2 but not period 1. Then user A would need to pay the LRMC charge, even though they never use the new line. User B would not, even though they do.

3.155 The Authority has not reached a firm view about this and has therefore not reached a firm view about whether other TPM charges would need to be adjusted if an LRMC charge is needed. The Authority would welcome submitters' views on these points. The Authority's current preferred approach is to specify that Transpower should consider whether an adjustment is needed to other TPM charges to promote the Authority's statutory objective, but is considering whether it should be more specific about the adjustment.

3.156 The second issues paper provided that an LRMC charge could only be included if a price signal was required over and above the price signals provided by nodal pricing and other transmission charges. It is now proposed that an LRMC charge may only be included if a price signal is required, over and above the price signals provided by nodal pricing, other transmission charges and any grid support arrangements relied on by Transpower to efficiently defer transmission investment.

3.157 The second issues paper also proposed that the LRMC charge must complement or augment, but not duplicate, price signals provided by nodal pricing and other transmission charges. In addition to those requirements, it is now proposed that an LRMC charge must also complement or augment, but not duplicate, price signals provided by any grid support arrangements relied on by Transpower to efficiently defer transmission investment.

3.158 The purpose of both these changes is simply to clarify that an LRMC charge must be considered in the context of all the ways that Transpower has of efficiently deferring investment.

The PDP would not apply to inefficient exit

Proposal

3.159 The proposed guidelines:

(a) no longer provide that the PDP would apply to inefficient exit

(b) no longer provide that a distributor could obtain a prudent discount if one of its load customers faced a transmission charge that exceeds the standalone costs for delivering electricity to it.

(c) no longer provides that a distributor needs to build generation to qualify for a prudent discount when it is privately beneficial but not efficient to bypass the grid.

Discussion

3.160 The second issues paper proposed that the PDP would be retained but extended so that prudent discounts would be available:

(a) for the expected life of the relevant asset

(b) 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) 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) to a customer that could establish that its transmission charges exceed the standalone costs for delivering electricity to it

(e) when the customer is a distributor with an embedded consumer in the same circumstances as in (c) or (d) above.

3.161 The Authority proposed that the PDP apply to inefficient exit because, provided a customer is paying charges equal to at least incremental cost, it is efficient to continue to charge the customer rather than for it to exit. Moreover, if the customer can be retained and they contribute to common costs, this would lower the rate of the residual charge and therefore reduce the incentives for inefficient behaviour caused by that charge.

3.162 The Authority received extensive feedback on extending the prudent discount to address inefficient exit ((c) and the corresponding part of (e)). Some submitters supported the extension of the PDP to avoid inefficient exit (as well as the extensions proposed under (a), (b) and (e)).[78] However, many submitters raised concerns that the extension of the PDP to cover inefficient exit would lead to greater inefficiency.[79]

3.163 Some parties were concerned that extending the PDP to inefficient exit was outside the Authority's ambit and that it was inappropriate for the Authority to consider. The Authority disagrees. The Authority considers that the question of whether transmission charges should be adjusted to avoid inefficient behaviour is within the Authority's responsibility. An example of this is the situation in which a customer inefficiently disconnects from the grid because its behaviour is sensitive to the amount of common costs recovered by its transmission charges.

3.164 Several parties noted that a business that seeks a prudent discount will have more information about its own prospects than the party making the decision. A business would therefore be encouraged to obfuscate its actual situation and seek a prudent discount even when its circumstances did not in fact warrant it, ie, it wouldn't have exited.

3.165 If the situation in the previous paragraph occurs, it would be inefficient. This is because there would be no prospect of inefficient exit and therefore no efficiency gain from granting a prudent discount. In addition, there would be resources wasted in the business's efforts to gain the prudent discount, in the appropriate party making the

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78 E-Type Engineering, Grey Power Southland, Market South, McIntyre Dick and Partners, Otago Chamber of Commerce, Otago Southland Employers' Association, Preston Russell Law, Sarah Dowie, South Port New Zealand, Southland Chamber of Commerce, Southland Manufacturers Trust, Stabicraft Marine, Gore District Council, Invercargill District Council ,Southland District Council, Venture Southland, Contact Energy, Meridian, NERA for Meridian, Norske Skog, Northpower, Oji Fibre Solutions, NZAS; submissions on the second issues paper.

79 Genesis Energy, Top Energy, Counties Power, Molly Melhuish, Fonterra, Castalia for Genesis, King Country Energy (KCE), Pioneer, Vector, EA Networks, Unison, Orion, HoustonKemp for Trustpower, Mighty River Power, Powerco, Transpower, Trustpower, PwC (for 14 EDBs), Electric Power Optimisation Centre. Norske Skog and NZAS indicated that they supported the extension of the PDP to inefficient exit but raised concerns with the detail of the proposal. New Zealand Steel raised concerns with the detail of the proposal.

decision, and in any subsequent appeals and litigation. This resource waste could be considerable, given the amount that is potentially at stake. Further, if a prudent discount is granted, it would raise the residual charge to other users and, although most of the effect would be a wealth transfer, this may also have negative implications for efficiency.

3.166 In addition, some direct consumers have indicated to the Authority that they do not consider PDPs provide enough certainty to make long-term investment and operational decisions.

3.167 Valid concerns were raised by submitters about the effect on competitive neutrality of a prudent discount for exit. This is most obvious where the firm had a direct competitor. For example, if one supermarket company found that it was facing the prospect of exiting the market because it was unable to compete with another supermarket company, giving the former a prudent discount would be no different in principle from exempting it from council rates because it could not otherwise compete with its competitor. This clearly creates dynamic inefficiency.

3.168 However, the concern is potentially worse than this. Even if the business granted a prudent discount does not have an obvious competitor in its product market, reducing its charges mean that it is better able to compete in its product market and in the market for labour and capital, and so adversely affect other businesses who do not receive the prudent discount. To extend the analogy above, if a large manufacturing plant was given an exemption from council rates because it would otherwise exit, the general equilibrium working of product and factor markets mean that the costs would be spread across other parties, which could potentially drive another party that was paying its council rates out of business. This is also inefficient.

3.169 These examples highlight that the granting of a prudent discount for a particular transmission customer is only likely to be efficient if it is disproportionately impacted by transmission prices compared with the average New Zealand business and compared to its competitors in product and factor markets – ie, transmission charges are a relatively large part of its total costs.

3.170 For these reasons, there are real questions about whether the proposal will enhance efficiency. Accordingly, the Authority proposes not to retain the proposed extension of the PDP to inefficient exit.

3.171 The draft guidelines in the second issues paper provide that a PDP be available to a distributor that can build DG to inefficiently bypass the grid. Several submitters[80] suggested that the distributor should not have to build the DG itself.

3.172 It was the Authority's intention that a prudent discount would be available in these circumstances. This is because the inefficiency problem is the same whether or not the customer builds the DG itself. Accordingly, the proposed guidelines have been amended to no longer refer to the requirements to 'build generation' to give effect to this intention.

3.173 The Authority also proposes to remove the proposal that a distributor could obtain a prudent discount if one of its load customers faced a transmission charge that exceeds the standalone costs for delivering electricity to it. This is because it is in the distributor's own hands to change the charge so it is lower than stand-alone cost. Together the proposal in this section means part (e) in paragraph 3.160 would be entirely removed.

80 See PwC (for 14 EDBs) and Top Energy submissions on the second issues paper.

Maintaining competitive neutrality between grid connected generation, DG and DR

Proposal

3.174 The proposed guidelines require that the TPM specify that, as far as is practicable, the TPM must be directed at facilitating competitive neutrality between grid connected generation, DG and DR.

Discussion

3.175 The second issues paper proposed that the residual charge would be applied to load and calculated according to capacity.

3.176 Some distributors have indicated they would pass on the residual charge to DG, to the extent that the distributors were charged for the operation of DG in calculation of the residual. If the distributors did, it could provide an inefficient disincentive for investment in DG relative to grid connected generation, and undermine competition from DG, even if the residual calculation were calculated using a lag. This is because the DG would face the residual charge, but grid-connected generation would not.

3.177 The Authority has now decided at this stage not to remove the provision under the DGPPs that distributors can charge DG no more than incremental cost. This will avoid the problem discussed in the previous paragraph. Specifically, if the residual were based on gross AMD, the residual charge that distributors pay would be invariant to the presence or absence of DG. As a result, distributors would be unable to argue that DG should bear any part of the residual.

3.178 However, the Authority considers that it would be desirable to establish the principle that the outcome being sought with the reforms to the TPM guidelines, the DGPPs and ACOT arrangements, and the distribution pricing principles, is that there should be competitive neutrality between grid connected generation, DG and DR.

Cap on transmission charges

Proposal

3.179 The proposed guidelines provide that there would be a price cap on transmission charges in regard to distributors and direct consumers.

3.180 The proposed cap is expressed in relation to a base value for each year. For a distributor, the base value is the total of the electricity bills (including all charges in respect of transmission, distribution, energy, levies and taxes) of all the distributor's customers in the 2019/20 pricing year, plus inflation. For a direct connect consumer, the base value is the direct consumer's total electricity bill in the 2019/2020 pricing year (including all charges in respect of transmission, energy, levies and taxes), plus inflation (CPI).

3.181 The proposed cap is also expressed in relation to a "net charge". For a distributor, the net charge will include the sum of the electricity bills of all of the distributor's customers for the year (including all charges in respect of transmission, distribution, energy, levies, and taxes). For a direct consumer, the net charge will include the direct consumer's electricity bill for the year (including all charges in respect of transmission, energy, levies and taxes). In both cases, the net charge will be exclusive of any amount payable by the distributor or direct consumer for the year in respect of an LRMC charge, kvar charge, any charge attributable to assets commissioned after the end of the 2019/20 pricing year, any AoB charge for further assets included as eligible investments under the additional component, and any increase in the distributor's or direct consumer's uncapped charges as a result of the optimisation of an investment or a material change in circumstances.

3.182 The amount of the cap is:[81]

(a) For each distributor 103.5% of the distributor's base value in that year

(b) For each direct consumer 103.5% of the direct consumer's base value. The level of the cap for a direct consumer starts to rise by two percentage points per annum three years after the date the TPM comes into force or when Transpower extends the AoB charge to other pre-guidelines assets if it does so and that occurs earlier. That is, in the first year the percentage increases, the cap rises to 105.5% of the direct consumer's base value in that year, the next it rises to 107.5% of the direct consumer's base value in that year, and so on.

3.183 The guidelines require the TPM to provide that, if a distributor's or direct consumer's transmission charges would increase in a year such that the distributor's or direct consumer's net charge would exceed the amount of the cap, Transpower must reduce the distributor's or direct consumer's transmission charges for the relevant year such that the net charge does not exceed the amount of the cap.

3.184 If in any year the cap does not result in a reduction in transmission charges for a distributor or direct consumer, no cap applies to the distributor's or direct consumer's transmission charges in any subsequent year.

3.185 If a distributor's or direct consumer's total transmission charges, less the components specified in the next sentence would be below incremental cost in a year those charges must be set at the incremental cost. The components deducted in the previous sentence are the amount payable by the distributor or direct consumer for the year in respect of an LRMC charge, kvar charge, any charge attributable to assets commissioned after the end of the 2019/20 pricing year, any AoB charge for further assets included as eligible investments under the additional component, and any

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81 This footnote expresses the cap mathematically.

Let

B(t)	=	a distributor's estimated total electricity bill (as defined above) , or the estimated total electricity bill of a direct connect consumer
ETX(t)	=	the transmission charges excluded from the customer's net transmission charges
BV(t)	=	the base value for the customer
α	=	103.5% for a distributor. It is 103.5% for a direct connect consumer, rising by 2 percentage points per annum after the earlier of 3 years after the TPM comes into force and when Transpower extends the AoB charge under the AoB additional component (if it does).

All variables are expressed in real (ie, inflation adjusted) terms. Year 0 is 2019/20.

Then

$$BV(t) = B(0)$$

The cap means that the customer's net transmission charges are reduced so that the customer's electricity bill satisfies

$$B(t) - ETX(t) \leq \alpha . BV(t)$$

increase in the distributor's or direct consumer's uncapped charges as a result of the optimisation of an investment or a material change in circumstances.

3.186 If there is a material increase in a distributor's or direct consumer's load, Transpower would be required to adjust the cap on the distributor's or direct consumer's transmission charges by the same percentage as the increase in the customer's load.

3.187 If the cap would prevent Transpower from recovering its recoverable revenue, all caps would be increased proportionately to the extent necessary so that it is possible for Transpower to recover its recoverable revenue.

3.188 Transpower would be required to review the operation of the cap in relation to the distributors and direct consumers whose charges continue to be reduced by the cap, to be carried out in 2025 and completed not later than the end of that year.

3.189 The cap would not apply to generators (who do not pay the residual charge except to the extent that they have load).

Discussion

3.190 The second issues paper did not propose any transitional provisions. That was because the modelled indicative initial impact for almost all residential consumers was modest. The largest increase for residential consumers was modelled to be 5.8%. For some larger industrial plants the indicative initial impact would have been higher. However, these industrial plants would have been eligible to apply for a prudent discount for inefficient exit.

3.191 There are three reasons why the Authority believes a cap may now be warranted:

(a) Durability—limiting the initial impact of the charges would mitigate concerns that the TPM proposal is resulting in unexpected increases in charges.

(b) Certainty—because the guidelines would now give Transpower more flexibility about the residual allocator, customers would be left uncertain as to what their charge would be. A cap would provide relative certainty.

(c) Removal of the prudent discount for exit—limiting the initial impact of charges is an alternative to extending the prudent discount policy to reduce incentives for inefficient exit as a result of the introduction of the new TPM, by allowing businesses that might otherwise exit time to adjust to the new charges. Thus for a number of direct customers, the cap would be binding and would remain binding for many years.

3.192 In addition, some submitters suggested the wealth transfers under the proposal could affect its durability, and a transition could help address this issue.

3.193 The Authority considers the concerns about durability of the proposal mainly arise with respect to the potential impact on consumers (residential, and direct consumers), rather than generators. The Authority is proposing that the cap would relate to estimated consumer electricity bills. Generators would not be subject to the residual charge under its proposal except to the extent of their load, which would limit the impact on generators from the Authority's proposal.

3.194 The proposed cap would not apply in regard to the LRMC charge, any kvar charge and any charges attributable to assets commissioned after the end of the 2019/20 pricing year, as doing so would materially reduce the efficiency of those charges.[82] Neither would it apply to any AoB charge for further assets included as eligible investments under the additional component, nor to any increase in a distributor's or direct consumer's uncapped charges as a result of optimisation or a material change in circumstances review.

3.195 A distributor's or direct consumer's net charge would exclude any charge attributable to assets commissioned after the end of the 2019/20 pricing year. Accordingly, Transpower would need to establish a method for distinguishing expenses for assets commissioned before that date from expenses commissioned after that date. For example, with respect to overhead and unallocated expenses that are recovered through the residual, it could limit the amount subject to the cap to the amount of overhead and unallocated operating expenses in the year prior to the cut-off, with any excess being excluded from the cap.

3.196 The fall in interest rates since 2014 when the Commerce Commission (Commission) last reset the WACC and thus the revenue requirements for Transpower and price-regulated distributors means that it is possible that the Commission may use a lower WACC to reset the price paths that apply to Transpower and price-regulated distributors from April 2020. If this happens, it may mean that for many distributors, the cap would not result in a reduction in transmission charges. The impact of the estimated possible change in WACC is among the changes modelled in Appendix F.

3.197 The modelled impact on distributors' customers does depend on an assumption that distributors would not pass on charges to particular groups of customers in a disproportionate manner. However, the indications from some distributors, such as some in the upper North Island, of how they would pass on charges, suggest this assumption would not necessarily hold.

3.198 This proposal does not prevent distributors disproportionately passing on the increase in charges to particular groups of consumers. However, it does give them the ability to cap the initial real increase in their customers' charges to 3.5 percent of their estimated 2019/20 total electricity bill.

3.199 If a distributor's or direct consumer's total transmission charges, less the components specified in the next sentence would be below incremental cost in a year, those charges must be set at the incremental cost. The components deducted in the previous sentence are the amount payable by the distributor or direct consumer for the year in respect of an LRMC charge, kvar charge, any charge attributable to assets commissioned after the end of the 2019/20 pricing year, any AoB charge for further assets included as eligible investments under the additional component, and any increase in the distributor's or direct consumer's uncapped charges as a result of the optimisation of an investment or a material change in circumstances. This would mean that the customer was not being cross-subsidised by other customers.

3.200 The cap would change for the direct consumers from the earlier of 3 years after the date on which the TPM comes into force or the date on which Transpower begins to apply the AoB charge to further pre-guidelines assets. The cap would be set at 105.5% of the direct consumer's base value, increasing by 2 percentage points on the base value in each subsequent year. However, the increase in their transmission charges on this initial set of pre-guideline assets would be limited to 2 percentage points per year after

[82] New transmission assets are asset commissioned after the end of the 2020 pricing year.

adjustment for inflation. This would ensure that the charges for those customers would become cost-reflective over the long run. This is appropriate as it ensures that those customers (for whom transmission costs are a significant proportion of input costs) will eventually face cost-reflective charges and so make efficient investment and operational decisions.

3.201 Since Transpower could extend the AoB charges to potentially all pre-guidelines assets, both the magnitude and the incidence of price increases may differ from that in the second issues paper, as is discussed further in the chapter on the impact of the proposals below. Clause 12.89(2) of the Code requires that Transpower's TPM proposal must include indicative prices. This would allow parties to consider the impact of the TPM proposal.

Supplementary consultation modelling results

3.202 Appendix F provides the supplementary consultation modelling results. Two modelling scenarios are presented, each estimating the charges for the first year of implementation of the TPM proposal.

3.203 Scenario 1 includes:

(a) a capping mechanism intended to limit any transmission charge increase to no more than 3.5% of end consumers' electricity bills in the year of implementation

(b) the North Island grid upgrade (NIGU) investment remodelled (as discussed below)

(c) transmission and distribution charges adjusted to reflect the possibility of a reduced weighted average cost of capital (WACC) for Transpower and regulated distributors for Regulatory Control Period 3 (RCP3), which commences from April 2020

(d) some anomalies addressed.

3.204 The charts and tables in scenario1 show that changes in the WACC could more than offset changes to the TPM.

3.205 The 'status quo' is the current TPM and the current WACC for the regulatory period 2015-2020. The charts and tables therefore do not provide a comparison with what would happen under the current TPM with a WACC adjustment.

3.206 Scenario 2 includes the same effects as scenario 1 except that it does not include the WACC adjustment to Transpower and electricity distribution businesses (distributors) that is assumed to apply for RCP3.

3.207 Refer to Appendix F for further details of modelling results.

4 Cost benefit analysis and evaluation of alternatives

Introduction

4.1 The Authority commissioned Oakley Greenwood (OGW) to prepare an independent cost-benefit-analysis (CBA) of its TPM proposal, as outlined in the second issues paper. The Authority received extensive feedback on the CBA in the second issues paper.

4.2 The Authority requested OGW to consider the feedback and provide advice on whether the CBA needed to be changed as a result of the feedback.

4.3 The Authority also requested OGW to consider whether changes were required to the CBA as a result of the proposed refinements to the proposal in the second issues paper.

4.4 This chapter:

(a) provides OGW's response to submissions on the second issues paper CBA (Appendix B)[83]

(b) provides the Authority's response to submissions, where it is appropriate for the Authority, rather than OGW, to respond. This mainly relates to the CBA assumptions that the Authority provided to OGW (Appendix D)

(c) provides the Authority's view as to whether the CBA is robust, after considering submissions and OGW's response to submissions

(d) outlines OGW's advice (attached as Appendix C) and assesses whether changes are required to the CBA as a result of the refinements the Authority is considering.

OGW's response to submissions on the second issues paper CBA

4.5 Several submissions on the second issues paper provided detailed criticisms of the CBA. A full report containing submitter comments on the CBA and OGW's responses is provided in Appendix B. The main criticisms were that the CBA:

(a) assumed the proposal is efficient[84]

(b) assessed the value of implementing an LRMC charge, not the Authority's proposal

(c) assumed diesel generator costs that did not reflect New Zealand conditions, significantly inflating the assessed benefits from removing the regional coincident peak demand (RCPD) charge[85]

(d) failed to consider all potential costs[86]

(e) relied on assumptions that were not robust.[87]

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83 The Authority is intending to publish its response to submissions on the second issues paper and this supplementary paper as separate documents. The Authority is presenting OGWs response to submissions on the CBA in order to provide context for the discussion in this chapter on the Authority's views on the submissions and OGWs response.

84 Appendix B, OGW responses to submissions, (p.6).

85 For example, Pioneer Generation submitted that OGW's assumed $550 per kW capital cost of diesel generators was too low. Refer Appendix X, OGW responses to submissions, (p.7).

86 Appendix B, OGW responses to submissions, (p.32-43).

87 Appendix B, OGW responses to submissions, (p.17-20).

4.6 Against this, some submissions agreed the CBA provided a reasonable assessment of the proposal, although some considered it did not adequately estimate all benefits.[88]

4.7 OGW full report is attached as Appendix B. In brief, OGW's response to the points raised above were:

(a) Because the Authority has only issued guidelines, it is appropriate to model a generic approach that is consistent with service-based and cost-reflective pricing. Leaving aside transactions and similar costs, applying such an approach leads to a conclusion that it will improve efficiency, not because it is assumed but because economic theory is clear that it will. However, allowing for transaction and related costs, opens up the possibility that the proposal could have negative benefits.[89]

(b) The CBA is a fair reflection of the Authority's proposal because LRMC is a reasonable proxy for cost-reflective, service-based charges.[90]

(c) The diesel generator costs applied are a fair reflection of the costs of small scale, self-contained and highly flexible units, rather than more permanent installations.[91]

(d) The costs that were not quantified are either immaterial or are not relevant to the Authority's proposal. While OGW agreed that implementation and administration costs could be higher, they advised they could also be lower and that OGW's sensitivity analysis adequately addressed the uncertainty in the Authority's proposal.[92]

(e) Many of the assumptions commented on by submitters were provided by the Authority.[93] The Authority considers these submitter points below.

The Authority's response to submissions, where it is appropriate for the Authority, rather than OGW, to respond

4.8 The Authority's response to submission points on the CBA where the Authority, rather than OGW, is best placed to respond is provided in Appendix D. In summary the main criticisms addressed in Appendix D were that the CBA:

(a) contained capital expenditure assumptions that were provided by the Authority, so they are not independent, and they are not robust

(b) outcome is highly uncertain because the proposal that it assesses is not highly prescriptive

(c) focused on the impacts on grid costs with limited consideration of the wider impacts to outside grid pricing and the sector in general

(d) should have considered regional economies and the quality of life of energy users

(e) appears to compare the proposed change with the current status quo

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88 For example, Business NZ submitted that the CBA should have assessed benefits from a greater incentive for customers to reveal their willingness to pay. NZAS submitted that the CBA should have assessed benefits from a reduction of economic barriers to the efficient ownership of sub-transmission assets.

89 Appendix B, OGW responses to submissions, (p.6).

90 Appendix B, OGW responses to submissions, (p.6).

91 Appendix B, OGW responses to submissions, (p.10-12).

92 Appendix B, OGW responses to submissions, (p.32-43).

93 Appendix B, OGW responses to submissions, (p.14).

(f) is separate from Concept's AoB forecasting, which makes it difficult to evaluate the impact of the proposed TPM.

4.9 In brief, the Authority's responses to the above points are as follows:

(a) There was a high level of uncertainty around future capital expenditure requirements when the CBA was prepared, exacerbated by the recent thermal closures in Auckland – evidence that capital expenditure requirements can change quickly and with little warning. The Authority did not have access to a robust 30 year transmission investment forecast that could be aligned to the 20 to 30 year period of the CBA. This would have required detailed information on the drivers of each investment.

The Authority examined a number of methods for forecasting capital expenditure and decided that the most robust method was to base forecasts on historical data. Given the uncertainty, the Authority conducted sensitivities on the cost of a given level of capital expenditure. The sensitivity analysis demonstrated that the proposal delivers benefits even where the cost of capital expenditure is well under half the base case scenario. Further, the Authority considers the 60:40 allocation of capital expenditure to load and generation was a reasonable assessment of the extent to which transmission expenditure benefits load and generation given that both generation and load benefit from transmission investment, but that, in general, load benefits more from reliability investments.

(b) The Authority agrees with some submissions that the proposed guidelines should be less prescriptive and required amendment to reflect more of an emphasis on guiding principles or broad criteria. This paper proposes amendments to the proposed guidelines on that basis. The Authority recognises that shifting to less prescriptive guidelines would increase the level of uncertainty about how the proposal will be implemented in practice and, hence, to what extent the benefits will vary from those estimated by the CBA. However, it also recognises that a trade-off exists. In developing the refinements, the Authority balanced the disadvantages of increased uncertainty with less prescription against the advantages of providing additional flexibility to Transpower. Because Transpower has greater operational knowledge than the Authority about electricity transmission, the Authority considers Transpower is best-placed to propose a detailed methodology. This is reflected in the Code requirement for the Authority to develop the TPM guidelines and for Transpower to develop the TPM itself. The Authority also considers that the uncertainty is mitigated by the requirement that the TPM further the Authority's statutory objective.

(c) The CBA's focus is consistent with the Authority's overarching economic objective for transmission pricing as described in the Authority's decision making and economic framework for transmission pricing (framework): "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.

(d) The Authority must adhere to its statutory objective. A substantial proportion of redistributions between regions amount to wealth transfers. The Authority's position as outlined in its interpretation of its statutory objective document (published on the Authority's website), is that wealth transfers are excluded from the Authority's decision-making, except to the extent that efficiency effects arise from wealth transfers. The Authority considers that regional redistribution can be inefficient to the extent that the revised charges in regions are not cost-reflective and service-based. The Authority considers that its proposal provides for more cost-reflective and service-based charges, which is efficient.

(e) The status quo scenario for the CBA relates to the current TPM, revised to take into account changes relating to Transpower's operational review.

(f) The modelling of the charges is for one year only whereas the CBA provides a 20 to 30 year assessment. The Authority does not consider that it is necessary for the two assessments to be aligned.

The Authority's view on the CBA after considering submissions and OGW's response to submissions

4.10 There have been criticisms of the CBA approach, its assumptions and its outcome. The Authority has reconsidered the CBA in light of submissions and OGW's responses to these submissions.

Background to development of the CBA approach

4.11 The Authority commissioned an expert party, OGW, to develop an independent CBA of the proposal outlined in the second issues paper. As chapter 8 of the second issues paper discusses, the Authority has a different view from OGW about the existence or extent of some of the costs and benefits provided by the proposal. For example, the Authority, unlike OGW, considers that its proposal will improve the timing, capacity and quality of replacement expenditure. Similarly, while the Authority and OGW agree that the proposal would incentivise efficient participation in grid (and alternative) investment decisions, there appear to differences about the extent of this benefit. The Authority continues to be of the view that the dynamic efficiency benefits from more efficient participation potentially offers among the highest level of economic benefits of its proposal, whereas OGW's sensitivity analysis suggests it considers they will be significantly smaller.

4.12 The OGW CBA was informed by submitter feedback on the October 2012 TPM proposal's CBA. This "top-down" CBA was criticised for being too simplistic, namely, that it assumed benefits by applying an efficiency factor – whereby the TPM proposal would make the market more efficient by a set percentage.

4.13 In response to feedback on this approach, the Authority developed the CBA working paper, released in September 2013, to seek feedback on best practice for a revised CBA. Feedback on the CBA working paper informed the Authority's preferences for the type of CBA undertaken by OGW. For example, an important finding was that a more complex "bottom-up" approach was required, but that this should be cross-checked against a "top-down" approach. The CBA approach was further informed by OGW's proposal. For example, OGW advised the Authority that a "top-down" approach was too high level to be useful as a cross-check on the "bottom-up" approach. The Authority accepted this view.

4.14 During the course of finalising the CBA methodology, the Authority discovered an error in the CBA working paper. The paper stated that "consumers' prices provide a direct means of testing the extent to which a given reform proposal does or does not promote the Authority's statutory objective."[94] This is inconsistent with the Authority's published Interpretation of the Authority's statutory objective document,[95] which states "only the

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94 CBA working paper, paragraph 10.6.

95 ibid, Paragraph A.6.

efficiency gains of an initiative should be treated as benefiting consumers, with wealth transfers excluded because they 'net off' among all electricity consumers once indirect wealth effects are taken into account." The Interpretation of the Authority's statutory objective document takes precedence in this situation, so changes in prices are viewed as wealth transfers and do not affect the Authority's decision-making, except to the extent there are efficiency effects.

Summary of response to feedback on the CBA approach, the assumptions applied and the CBA outcome

4.15 The consultation process demonstrated the need for a trade-off between complexity and simplicity. In general, simple CBAs are easy to understand and require fewer resources to develop and scrutinise. This encourages debate. Complex CBAs can be much more difficult to understand and they often require a lot of assumptions. However, they are likely to be more appropriate for complex decisions where there are multiple interacting variables.

4.16 The Authority recognises that transmission pricing is a highly complex subject matter with multiple interacting variables and uncertainty around the assumptions. However the Authority received feedback that some submitters do not support a complex approach.[96] Conversely, at least some of the calculations in the CBA were criticised as being overly simplistic.[97]

4.17 OGW noted in its report that "the modelling of complex decisions by multiple parties facing uncertainty over an extended period can only ever be an approximation".[98] Following a "top-down" CBA on a beneficiaries-pay approach, a CBA working paper and a "bottom-up CBA" on a beneficiaries-pay approach and an alternative approach, the Authority recognises that it is no closer to achieving a consensus around the most appropriate CBA approach for a transmission pricing proposal.

4.18 Further, the Authority recognises that opting for a more complex, "bottom-up" CBA for the second issues paper, may have restricted feedback on the CBA, except in the case of heavily resourced parties, or parties with a high vested interest in the outcome of the TPM review.

4.19 The Authority concedes that the CBA is not perfect; that it requires assumptions to complete in some cases and that the calculations are simplifications of how the market works in practise. This is true of most if not all CBAs. Conversely, the Authority considers that the OGW CBA was useful for informing the Authority's development and assessment of its proposal and encouraging debate about the extent to which the proposal provided net benefits. The Authority notes while many submitters did not provide detailed comments, other submitters did.

4.20 Furthermore, the need for assumptions is in fact a strength, not a weakness. These assumptions are implicit in top-down approaches and so not subject to scrutiny. Making them explicit allows them to be debated and tested.

4.21 However, the complexities and the need to make assumptions also mean that it is desirable to cross-check that the overall results are reasonable.

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96 For example, Trustpower submission on the second issues paper.

97 For example, PwC submitted that the HVDC benefit was too simplistic as it does not reflect the additional AoB charges that would be faced by generators under the proposed TPM and that would also be taken into account in any investment decisions.

98 Appendix B, OGW responses to submissions, (p.13).

4.22 As a high level check, the Authority asked OGW whether moving from a postage stamp charge to a cost-reflective, service-based charge of the kind the Authority is proposing, would likely provide positive net benefits, at least in principle. OGW responded that, in principle, such a change in methodology would almost certainly provide for net benefits, unless the implementation and administration costs were so large that they exceeded the positive benefits. OGW stated that the implementation and administration costs of the Authority's TPM proposal did not appear to be material compared to the assessed positive net benefits of the CBA. In other words, if the proposal is, in fact, cost-reflective and service-based, in principle it should provide for positive net benefits against the status quo TPM.

4.23 The Authority agrees with the OGW observations. It considers that this response by OGW, in conjunction with the additional sensitivity analysis OGW has undertaken, is a useful cross check to offset any uncertainty in the outcome of the CBA.

4.24 After considering all submissions and reviewing OGW's responses to submissions, the Authority is of the view that the CBA does not need to be changed on account of submissions. OGW has provided a clear defence of both its methodology and calculation, and the errors that were identified were only minor in nature and did not materially impact on the outcome of the CBA. In addition, the results of the CBA are supported by the qualitative assessment of the proposal.

4.25 The next section looks at whether changes to the CBA are required on account of the refinements the Authority is considering making to the proposed guidelines.

OGW report on whether the proposed refinements require adjustments to the CBA in the second issues paper

4.26 The Authority is consulting on refinements to the proposed guidelines. While its view was that the refinements are minor in nature, the Authority requested that OGW reconsider its CBA on the basis that all of the refinements under consideration are to be included in the proposed guidelines.

4.27 OGW's detailed report is attached in Appendix C. However, a summarised version of its views is set out in Table 3 below.

Table 3: **Summary of proposed refinements and OGW assessment of implications for the CBA**

Refinement	Impact on the CBA
AoB Providing Transpower with the flexibility to extend the coverage of the AoB charge The draft guidelines include as an additional component that Transpower must include an investment that is not an eligible investment as defined in the second issues paper as an eligible investment if it considers that doing so would be	Regarding new customer connections, both the AoB charge and the residual charge involve levying a fixed charge on a new customer. In both cases, as well as under the current TPM arrangements, there is the possibility that the overall charge may exceed a potential new customer's willingness to pay, despite that customer's willingness to pay being greater than Transpower's incremental cost of supply. In short, we didn't model any potential distortions stemming from the use of the residual charge versus the AoB charge versus the current TPM arrangements on the efficient connection of

Refinement	Impact on the CBA
practicable and consistent with the requirements of clause 12.89 of the Code and likely to yield net benefits. Transpower would be able to propose a transition if it decided to propose extending application of the AoB charge to pre-guidelines assets (other than those in the second issues paper).	new customers, because they all have similar attributes, hence we do not propose to change our CBA based on the Authority's proposed refinement.[99]
AoB The TPM must include a standard method and a simplified method or methods, and when determining the standard method and the simplified method, Transpower must balance the economic benefits of sending accurate price signals against the economic costs of developing, implementing and administering the relevant method	Trading off the improvements in economic efficiency versus implementation and administrative costs is appropriate. If anything, this may reduce the administrative costs of implementing the proposed changes, without affecting the efficiency. If anything, this would improve the outcomes, as compared to the CBA. That said, it is difficult to know exactly how this will translate into costs, therefore, we do not propose to adjust our CBA considering this change.[100]
AoB The draft guidelines provide that a) the principles for the valuation method are that it should result in charges that are: - service-based and cost-reflective - promote an efficient trade-off between: • the economic benefit of sending accurate price signals to customers and • the economic cost of developing, implementing and administering the	Our original CBA assumed that the valuation technique that applied to new assets would result in cost-reflective AoB charges, therefore promoting efficient investment in, operation of those assets. Therefore, the principles outlined in the guidelines we have reviewed do not affect our original CBA, in relation to how new assets will be charged for. Our original CBA also assumed that the valuation technique underpinning the recovery of Transpower's historical investments would not distort future consumption of investment decisions. The guidelines we have reviewed, which, amongst other things, provide for Transpower to adopt any approach that better promotes the Authority's statutory objective, does not lead us to alter this position.[101]

99 Appendix C, p.12.

100 Appendix C, p.13.

101 Appendix C, p.13.

Refinement	Impact on the CBA
valuation method and b) be based on: - an indexed historical cost approach or - another approach that better promotes the Authority's statutory objective.	
Marginal price adjustment mechanism for AoB charge The draft guidelines make the introduction of the marginal price adjustment mechanism an additional component (i.e., it is not compulsory, rather Transpower will be required to introduce it if the benefits exceed the costs)	Our position is that given the increasing returns to scale from making lumpy transmission investments, Transpower is likely to consider an additional marginal price signal both practicable and consistent with the requirements of clause 12.89 of the Code, hence, on the balance of probabilities, it will be introduced. As such, we do not consider there to be any reason to adjust our original CBA.[102]
Overhead and unallocated expenses Requiring Transpower to make a more specific allocation to the connection charge for connection invesments and the AoB charge for eligible investments of overhead and unallocated expenses	More specifically, if the Authority was proposing to recover some "fixed" overhead and other expenses via the AoB charges for future assets, then this will distort the AoB price signal for future assets, as the marginal price signal (the AoB charge) exceeds the actual marginal cost of providing the service being priced…. The wording in the Guideline we reviewed indicates that the overhead and other expenses that are to be recovered through the AoB charge, must relate to the eligible investment. On the assumption that this clause is interpreted in a way that would only lead to marginal overhead and other costs being recovered via the AoB charge, we would not propose to change our CBA. Oakley Greenwood further note in Footnote 10: It should be noted that clause 39(a) may result in some fixed overhead and other expenses being recovered via future connection charges, however this is no different from under the current TPM, therefore, there is no incremental effect from the

102 Appendix C, p.14.

Refinement	Impact on the CBA
	retention of this provision in the Guidelines, hence why it doesn't affect the CBA. [103]
Residual Providing Transpower with the flexibility to develop the details of how the residual is allocated, subject to guiding principles. The draft guidelines also state that the residual charge: - to the extent that it can be economically achieved, does not create incentives or opportunities for designated transmission customers to inefficiently avoid the charge - is to be paid by designated transmission customers that have positive gross load - must be related to the size of the load of the transmission customer - must be designed such that a customer's residual charge will not change as a result of the customer's actions or the actions of another party other than Transpower - must be calculated to result in broadly equivalent charges for customers that are in broadly equivalent circumstances	The potential use of other possible residual allocations that may not be related to a measure of physical capacity (which was the assumption underpinning the CBA) would not lead us to change the CBA, subject to it: • Being very difficult for customers to avoid in the future, and • Reflecting a customer's reliance on the transmission system. This reflects the position that we stated in our original CBA that 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 therefore, cannot be reversed. The two provisos are that the recovery mechanism minimises the extent to which it: ▪ Distorts the future usage of the existing network (e.g., consumption decisions); and ▪ Leads customers (including generators and DGs) to make inefficient connection, disconnection or other investment decisions. Based on the wording included in the guidelines we have reviewed, particularly the need for Transpower to ensure that the "charge will not change as a result of the customer's actions or the actions of another party other than Transpower, such that it does not create incentives or opportunities for designated transmission customers to inefficiently avoid the residual charge", we think that the proposed refinements are consistent with the two provisos mentioned above. Therefore, we don't believe that this change to the guidelines materially impacts upon our original CBA.[104]
LRMC If Transpower were to propose implementation of an LRMC	Given that the concept of allowing Transpower to adopt an LRMC charge to complement or augment, but not duplicate an existing price signal aligns with

103 Appendix C, p.5.

104 Appendix C, p.11.

Refinement	Impact on the CBA
charge, Transpower is to consider whether any adjustments to other TPM charges are needed to promote the Authority's statutory objective	our original assumption, we see no need to revise our original CBA.[105]
PDP No longer extending the PDP to avoid inefficient exit of load	It is our view that by removing this component of the TPM, everything else being equal, there is a higher risk of large customer/s disconnecting from the transmission network, despite their willingness to pay for transmission services exceeding Transpower's avoidable cost, relative to what was assumed as part of the original CBA. Everything else being equal, this is an inefficient outcome, that will not be offset by any economic benefit that comes from guaranteeing that businesses cannot "game" this component of the TPM, or any other matter. Therefore, in the context of our original CBA, this would turn the current positive benefit that accrues from this component of the TPM into a zero benefit, as that benefit would now not be obtained.[106]

Cap
 	
Providing for a cap on price changes resulting from changes to charges for the eligible pre-guidelines assets specified in the second issues paper
	The impact on the CBA of any price capping arrangement depends on how this price cap is implemented in practice. If the transitional arrangements compromise the introduction of the AoB charge as it relates to aspects of our analysis that have contributed to positive economic benefits, in particular:
	
	• The application of the AoB charge to forward-looking, demand-driven, investments, or
	
	• The removal of the RCPD charge and subsequent replacement with a:
	
	    ■ residual charge that is non-distortionary and
	
	    ■ an AoB charge that is applied to some historical assets,
	
	then it would affect the results of the original CBA. However, given that the net charge on which the cap is placed excludes recovery of the cost of new investments ('any charge attributable to assets

105 Appendix C, p.7.

106 Appendix C, p.9.

Refinement	Impact on the CBA
	commissioned after the end of the 2019/20 pricing year'), the cap would not appear to compromise the AoB price signal as it relates to forward-looking demand-driven investments. Furthermore, it is our understanding that the cap would not involve the retention of the existing RCPD price signal to recover the costs of sunk investments, therefore we consider the original CBA does not need to be amended.[107]

Changes due to refinements of the proposal

4.28 In summary, OGW's advice is that all but one the refinements being considered would not materially change its view as to the expected net benefits of the second issues paper TPM proposal. OGW consider the refinements are relatively minor in nature and that they would not likely jeopardise or improve the proposal, to implement cost-reflective and service-based charges.

4.29 The one exception is in relation to the PDP. The Authority is proposing not to proceed with the proposal in the TPM second issues paper to extend the PDP in relation to inefficient exit. OGW responded that this would change the expected net benefits from the proposed PDP changes from $10.3m to $0 – a reduction of $10.3m.

4.30 The Authority is proposing not to proceed with the "inefficient exit" change to the PDP because it accepted the view of some submitters that it could lead to an increase in inefficiency. So while the Authority accepts that not having this provision reduces OGW's estimated net benefits of the proposal, the Authority considers that there would be no gain in net benefits from proceeding with "inefficient exit" provision. The Authority further notes that the CBA does not quantify other aspects of the Authority's proposed changes to the PDP, such as providing that a PDP would apply when a customer can source alternative sources of supply. The Authority considers that this would provide a material benefit. As such, the Authority considers that OGW's assessment of the benefits in relation to the PDP is overly conservative.

4.31 The effect of OGW's adjustment as result of the changes to the PDP mean the expected net benefits of the modified TPM proposal that OGW quantified, with all of the refinements in place, is $203m, down from the previous level of $213.3m.

4.32 In the Authority's view, all of the refinements it is now proposing to the draft guidelines in the second issues paper have the effect of clarifying them or advancing their intent. As a result, the Authority expects that the changes will not reduce and may increase the actual net benefits of the proposal. In broad terms, therefore, the Authority accepts OGW's assessment of the effects of the refinements on its CBA.

4.33 The Authority considers that the changes will lead to a more even-handed and pragmatic implementation of its proposals and so enhance the durability of the proposed guidelines. For example, its proposal that the gross load of each customer will be used

107 Appendix C, p.9.

to identify who will be liable for the residual charge will ensure there is no artificial and potentially contentious distinction between whether a customer is load or generation. Similarly, it considers its proposal that anomalies in the application of the residual allocator should be addressed so that similar parties are treated similarly will be seen as both even-handed and pragmatic.

4.34 In summary, Authority's view is that overall the proposed refinements will materially improve the proposal's durability and will increase the efficiency benefits above OGW's initial assessment.

Changes due to the DGPP decision

4.35 Since OGW reviewed the CBA, the Authority has decided to restrict access to ACOT to that DG that is helping defer or avoid transmission investment.

4.36 The Authority asked OGW to review whether the Authority's decision on the DGPP would have any impact on its CBA of the proposed TPM.

OGWs Advice on the Impact of the DGPP decision

4.37 OGW's advice is:

> "Our CBA made no explicit assumption around the existence or lack thereof of the Distributed Generation Pricing Principles (DGPPs), or the ACOT payment mechanism under those DGPPs. Rather, we simply assumed that all transmission customers (eg, direct connect customers, consumer-owned distribution businesses) would:
>
> (a) be presented with a:
>
> (i) cost-reflective price signal in relation to the future transmission investments that are required to service them, via the AoB charge relating to future investments
>
> (ii) a price signal that de-links the recovery of residual costs including the costs of historical investments from future consumption and investment behaviour, and
>
> (b) Have an incentive to efficiently respond to those price signals in a way that maximises economic efficiency, which is also in the long-term interests of their customers.
>
> Under the base case, we assumed that the RCPD price signal would continue to trigger investments that are financially attractive, when priced against that RCPD price signal, even if those investments may be otherwise uneconomic. We did not explicitly assume that the ACOT payment mechanism was a necessary pre-requisite for any potentially uneconomic DG investment being built under our base case modelling, primarily because our modelling focused on the construction of smaller scale, diesel generation sets that could in theory be located behind-the-meter. That said, the continued existence of the ACOT payment mechanism would certainly not inhibit small scale, distributed generation sets, being built. Our analysis did not reflect any potential for the RCPD price signal to encourage investment in uneconomic grid-side renewable distributed generation, therefore, if any such reduction did occur as a result of the proposed changes to the DGPP, this would be an additional benefit not otherwise captured in our analysis.

If the ACOT payment mechanism (as it applies to new DG) is removed, yet the RCPD price signal is retained, then our preliminary view is that:

(a) Direct connect customers and unregulated consumer-owned distribution businesses are still likely to be incentivised to make financially attractive investments in DG (that may be uneconomic) in response to the RCPD price signal, as they or their owners directly benefit from any reduction in transmission charges,

(b) The incentive to construct behind-the-meter distributed generation facilities (that may be uneconomic) within areas served by regulated electricity distribution businesses is still there, as customers who are proponents can presumably seek exposure to the RCPD price signal through their retail charge, and

(c) Everything else being equal, the incentive to construct larger scale, grid-side distributed generation facilities within the areas served by regulated electricity distribution businesses would be reduced. However, there is even some uncertainty with regards to this outcome, as it is likely to depend on how the commercial arrangements supporting the construction of such facilities evolve in response to the removal of the ACOT payment mechanism. In particular, it will depend on whether DG proponents can establish a commercial model that allows them to leverage the benefits (in terms of lower transmission charges) that accrue to final end customers from the operation of the DG facility.

For completeness, it is noted that demand response is not affected by the removal of the ACOT payment mechanism.

On balance, given that the RCPD charge will be retained under these revised arrangements, and given our CBA focused more on smaller scale, distributed generation facilities as well as demand response, we do not believe that our base case CBA needs to be adjusted as a result of the removal of the ACOT payment mechanism."

The Authority's view on the impact of the DGPP decision, given OGW's advice

4.38 The Authority's decision on the DGPP alters the counterfactual for assessing the net benefits of the proposed TPM guidelines. More specifically, the DGPP decision could reduce the level of inefficient DG investment that would otherwise be expected under the TPM counterfactual case.

4.39 In its DGPP analysis, the Authority projects a benefit of $23 million (base case) from reduced inefficient DG investment. If there was a direct overlap in sources of investment benefit, the DGPP decision would reduce the net benefits expected from the proposed TPM guidelines by $23 million.

4.40 However, the Authority expects most of the gain from the DGPP decision to come from reduced investment in inefficient renewable generation connected to distribution networks, but not behind load customer's meter (referred to by OGW as 'grid-side'). Conversely, OGW's analysis of DG focused more on the construction of smaller scale, diesel generation sets that could in theory be located behind a load customer's meter. Furthermore, OGW did not explicitly consider the incentives under the arrangements prior to the change in the DGPPsto encourage inefficient investment in 'grid-side' renewable DG. Any reduction in such investment would have been a potential source of additional benefit in OGW's analysis.

4.41 Given these factors, the Authority considers that the effect of the DGPP decision on net benefits from the proposed TPM guidelines is likely to range between no impact and a reduction of $23 million, and is more likely to be towards the smaller end of this range.

5 Discussion of the impacts of the proposal

5.1 The refinements discussed in chapter 3 have been proposed because they are expected to further the Authority's statutory objective. This chapter discusses the other likely impacts (particularly on charges) of each of the refinements to the proposed guidelines, and then assesses their overall impact.[108]

Minimum coverage for AoB charge

5.2 The impact of providing for a minimum coverage of the AoB charge depends on whether Transpower considers a coverage broader than that proposed in the second issues paper would be practicable and consistent with the requirements of clause 12.89 of the Code. At one extreme, Transpower could propose the AoB charge apply to all interconnected grid assets. At the other, it could propose the charge applies to no more investments than those proposed in the second issues paper.

5.3 In the latter case, there is no change from the guidelines proposed in the second issues paper, so the modelling in the second issues paper, as updated for this paper, would still be relevant.

5.4 In the former case, the general nature of the change would be to:

(a) apply relatively more of the charges to generation and relatively less to load, since generation pays the AoB charge but not the residual charge

(b) within load, shift the charges from those areas that have benefitted from the post-2004 investments in the interconnected grid towards those that face relatively small AoB charges under the proposals in the second issues paper (see figure 22 of the second issues paper)

(c) potentially, shift charges from load that has a low capacity factor to load that has a high capacity factor if charges within an AoB are allocated to load on a capacity basis.

5.5 If, instead, Transpower chooses to apply the AoB charge to some but not all of the remaining pre-guideline assets, the effect will be to shift the balance of charges towards the beneficiaries of the assets it includes.

5.6 If Transpower proposes a transition for implementing the AoB charge on these additional investments, the likely effect is to mute the immediate impact of the changes discussed above.

Trading off accuracy for practicality in assessing the benefits from investments

5.7 The impact of trading off accuracy for practicality will depend on the approach that Transpower chooses to take to estimate benefits. Applying more simplified approaches rather than more accurate approaches is more likely to result in:

(a) AoB charges applying to some non-beneficiaries and/or not applying to some beneficiaries of the investments in question

108 This chapter assumes that distributors pass on any changes in transmission charges to their customers roughly in proportion to their existing charges. Whether that happens in practice depends on the choices that distributors actually make.

(b) disproportionately charging some beneficiaries of an investment, and under-charging other beneficiaries of the investment.

5.8 These effects may affect the durability of the proposal and increase the risk of legal challenge. Conversely, a practical approach is likely to be less open to judgement, increasing durability and reducing the risk of legal challenge. What happens in reality would depend on the method used.

The calculation of net private benefits for the AoB charge should include LCE

5.9 The general effect of this clarification is to ensure that a customer's loss of LCE is taken into account in assessing the net benefit that a customer gets from a new investment. Both under the status quo and under the Authority's proposal, the LCE for an asset (after settlement of financial transmission rights) is allocated in proportion to the customers who paid charges in relation to the asset.

5.10 When Transpower proposes a new investment to reduce a capacity constraint in that asset, the customers who lose most LCE will be those who paid most charges in relation to the existing asset. Suppose for example, an asset benefits two regions, one of which is growing rapidly and the other is not. Other things being equal, it is likely that loss of LCE for the slow growing region will be a relatively bigger proportion of the net private benefits (including LCE) it derives from the new investment. As a result, the rapidly growing region is likely to pay relatively more of the cost of the new investment.

5.11 The Authority's modelling in the second issues paper and in this supplementary consultation paper has not taken account of the loss of LCE that customers would have suffered had they been subject to an AoB charge for pre-existing assets. For example, the North Island grid upgrade (NIGU) would have reduced the LCE for related transmission assets. It is likely that, had those assets been subject to an AoB charge rather than the postage stamp interconnection charge, the faster growing parts of Auckland would have benefited disproportionately from the new investment compared to the notional amount of LCE they would have lost on the pre-existing complementary AoB assets. Accordingly, it can be expected that, if LCE had been taken into account, the charges for slower growing customers would have been modelled to be less than that modelling suggested, and charges for faster growing customers would have been modelled to be higher.

Impact of proposed refinement to ensure AoB charges for post-guideline investments are service-based and cost-reflective

5.12 This section covers the impact of this issue for post-guideline investments. The next section covers the impact for pre-guideline investments.

5.13 This refinement proposes clarification to the method for determining AoB charges. It does not alter the intent of the second issues paper and so no significant change is expected as a result of this refinement.

5.14 The proposed refinement provides for the use of indexed historic cost as the basis of determining the AoB charges rather than replacement cost. Since indexed historic cost is intended as a proxy for replacement cost, the effect should be much the same. From the perspective of any individual customer, the variations compared to a true replacement cost approach are likely to be minor. The main difference between the two approaches is that the historical cost approach is likely to be less expensive to implement and would involve less judgement, so would involve less costs over the long run, but this would have a minimal impact on transmission charges.

Impact of proposed refinement to ensure AoB charges for pre-guideline investments are service-based and cost-reflective

5.15 The second issues paper proposed that pre-guideline investments be valued at DHC. Compared to this, the proposal to use service-based and cost-reflective charges is to reduce the charges on near-new investments and increase the charges on older assets. The exact impact depends on to what extent Transpower decides to extend the AoB charge to more pre-guideline investments.

Impact of proposed refinement to scale back TPM charges if necessary

5.16 This refinement proposes that if applying an indexed historic cost approach to pre-guideline investments would result in an over-recovery of Transpower's recoverable revenue, then, in order, the residual charge (excluding overheads and unallocated expenses) and then the charges to recover overheads and unallocated expenses should be reduced. If reducing both to zero still results in an over-recovery of Transpower's recoverable revenue, then the charges for pre-guideline AoB investments would be scaled back using a method to be determined by Transpower.

5.17 The impact of this refinement depends on the choices Transpower makes under the heading "Minimum coverage for AoB charge" above:

(a) If it decides not to extend the coverage at all, then it is likely that no scaling back of charges would be required, and the charges would be much as described in the second issues paper.

(b) If it decides to extend the coverage to all pre-guideline investments, then it is likely that the residual charge and possibly the charge to recover unallocated operating expenses and overhead and would need to be scaled back. Since each customer's residual charge is designed to be related to the size of the customer's load, the effect should be a relatively uniform lowering of the residual charge across load customers. The impact on generation customers will depend on how much their connection charges are reduced as a result of scaling back unallocated operating expenses and overhead, but would be smaller than for load (because of the effect of scaling the residual). If the AoB charge for pre-guideline investments also has to be scaled back, the impact would depend on the method that Transpower recommends for scaling it back. For example, if it proposes that it be scaled back proportionately, the impact would be approximately proportionate to the unscaled AoB charges the customer faces.

(c) If it decides to extend the coverage to only some pre-guideline investments (other than eligible investments identified in the second issues paper), the impact described in the previous sub-paragraph would be moderated.

Optimisation available only for high value investments

5.18 This proposal would only have an impact if Transpower chooses to introduce an AoB charge for pre-guideline low value investments. To the extent it does, it may mean that the charges would be higher for some low value pre-guideline investments that would otherwise have been optimised.

Allowing for an additional component to align the method for charging for connection assets with the method for charging for AoB assets

5.19 If Transpower decides to recommend aligning connection assets with interconnected grid assets, it is not likely that connection charges on individual assets would change much. This is because, under both the current pooled method for calculating connection charges and the indexed, historical cost (IHC) method, charges are calculated independent of an asset's age.

5.20 If Transpower was able to demonstrate that the current valuation method for connection charges is consistent with the interconnection asset valuation methodology, it would not be necessary to alter the existing connection charge arrangements.

The marginal price signal for a new investment should be an additional component

5.21 This marginal price signal would only apply to new investments after the date of the guidelines. As an additional component, its impact would depend on whether or not it is introduced. If it is introduced, the Authority considers it unlikely that it would be used extensively. As a result, the impact of both introducing it, and the decision not to introduce it for an increase in Transpower's costs, are likely to be relatively small. It would have no impact on initial charges.

Transpower should seek to make a more specific allocation to the connection charge and the AoB charge of overhead and unallocated expenses

5.22 The general effect of this proposal would be to reduce the charges for overhead and unallocated expenses and increase AoB charges and connection charges. It is not possible to be specific about how an individual customer's charges would be impacted, since it depends on to which AoB investments Transpower allocates the relevant overhead and unallocated expenses. However, to the extent that this proposal is implemented, it would reduce the residual charge and, potentially, connection charges for generators (since their connection charges include an allocation of these costs). The size of the reductions would depend on the extent to which it was possible to allocate these costs to customers through the connection and AoB charges.

The load of each customer should be used as the basis for determining who is liable for the residual

5.23 The proposed guidelines propose that liability for the residual charge is determined by the load of every customer rather than just applying to load (and not to generation). This means that all parties with load would pay the residual charge even if they are a net generator. This would broaden the base across which the residual charge is calculated, although the effect is likely to be small. The change would also make the allocation easier to calculate, reducing costs. The overall impact though would be analogous to the status quo where any load is subject to the interconnection charge (note that generators currently pay a small interconnection charge).

The calculation of the residual (and if necessary, the AoB charge for load) should not be limited to gross AMD

5.24 The proposal permits Transpower to use a method related to gross load other than AMD to calculate the residual and if necessary the AoB charge. Since the guidelines require this measure to be related to the gross load of customers, and to be designed to avoid various adverse behavioural effects the impact of this refinement on the charges should be small with the exact effect dependent on the measure that Transpower chooses.

The calculation of the residual should avoid double counting and other anomalies

5.25 The proposed guidelines make it clear that the intent is that similar customers should face a similar residual charge.

5.26 Compared to the modelled charges in the second issues paper, this should reduce the charges for customers like Electricity Ashburton, Buller, and Westpower which appeared anomalously high.

5.27 These anomalies have arisen because under the current transmission pricing regime there is little incentive for rationalisation of spare transmission capacity, and this would become transparent in a transition to a new regime.

5.28 Overall, addressing these anomalies should have a minor impact on most load customers' charges, but should improve the durability of the residual charge and so the durability of the TPM.

The AoB charge of a large consumer would be tied to the consumer

5.29 This proposal would have no immediate impact. Over time, its impact would be to discourage large consumers from shifting supplier in an attempt to reduce their charges. It should therefore tend to counterfactually reduce the charges on other consumers.

If an LRMC charge is applied, Transpower should consider whether changes are needed to other TPM charges

5.30 The overall impact of this proposal would depend on whether Transpower concludes that other AoB charges should be adjusted, and if so which charges. It is therefore not possible to gauge the impact of this proposal at this stage. Suppose it decided to reduce an AoB charge for an asset to the extent that LRMC charges have been applied to the asset. The effect of this would be to shift charges for an investment from beneficiaries of the investment (under the AoB charge) to parties whose activities led Transpower to impose the LRMC charge, eg, they used the congested assets that Transpower was proposing to upgrade.

5.31 The other effect of this proposal, other things being equal, would be to lower the residual charge when the LRMC charge applied (ie prior to an investment), but to increase the residual charge when the other TPM charges are adjusted, assuming Transpower fully recovered its recoverable revenue.

The PDP should not apply to inefficient exit

5.32 The proposed guidelines have been amended to remove the possibility of granting a customer a prudent discount to avoid its inefficient exit. One of the main reasons for this is that the information asymmetry between the customer and the authority granting the prudent discount may have led to a customer getting a prudent discount even when they would not in fact have exited, which is inefficient.

5.33 The impact of this policy on other customers' charges depends on the extent to which prudent discounts would have been justified. For cases where the prudent discount would have avoided inefficient exit, the removal of the provision will increase other customers' charges a little, because the exiting customer would have made a contribution to common costs. Conversely, where the proposal avoids giving a prudent discount to customers who would not have exited, the impact of the proposal is to reduce other customers' charges a little.

5.34 The removal of the requirement for a generator to build generation to qualify for a PDP to avoid inefficient disconnection will broaden the scope for distributors to apply for a PDP. This means that these customers will now continue to contribute to common costs whereas before they would have had to inefficiently disconnect. The impact should therefore be to reduce their charges and also to reduce the residual and so cause a small reduction in the charges of other load customers.

5.35 The effect of removing the ability for a distributor to seek a PDP because of the charges faced by one of its customers is likely to have little impact in practice, since the distributor is free to reduce those charges themselves. However, it should therefore mean that the charges of the relevant distributors are counterfactually higher. As a result the residual would be counterfactually lower, meaning a small counterfactual reduction in the charges of other load customers.

Initial impact of the charges will be capped

5.36 For households, the impact will depend on the way distributors choose to pass on changes in transmission charges to consumers connected to the distributor's network. They could choose to pass on none of the change or all of the change. The rest of this section assumes that distributors choose to pass on transmission charges using the same methodology used to estimate the cap on transmission charges to distributors.

5.37 On this assumption, the effect of this refinement on households is likely to be minimal, since the charges modelled typically increased less than the cap anyway, and addressing charging anomalies would further limit increases in some households' electricity bills.

5.38 The proposed cap may also limit increases in charges for embedded commercial and industrial load customers connected to the distributor's network.

5.39 All these effects of the cap on actual consumer electricity charges would depend on how distributors chose to pass on increases in transmission charges to different consumer groups.

5.40 For direct consumers, the impact of the cap would be to substantially moderate any initial increase in charges, and to create an extended transition towards the charges that would apply without the cap. (The eventual charges are not the same as those that would apply without the cap, since the effect of the cap on charges relating to distributors is to reduce the revenue collected from distributors whose charges would otherwise increase more than the cap and so to increase the charges collectively faced by other load customers).

Overall impact of the refinements

5.41 The overall impact of the refinements mostly depends on the following factors:

(a) the extent to which Transpower proposes to extend the coverage of the AoB charge beyond what was proposed in the second issues paper, and to the extent it does, the transition it proposes

(b) the proposed cap

(c) the greater flexibility that Transpower has to design the residual charge allocator

(d) the removal of the PDP for inefficient exit.

5.42 To the extent that Transpower does not expand the coverage of the AoB charge, the effect of most of the refinements to the proposed guidelines in the second issues paper apart from the cap on all load parties is likely to be modest. (The removal of the PDP for inefficient exit could have a significant impact on individual customers). However, increases in TPM charges on load would be limited by the proposed cap. The proposed cap would mean the short to medium term impact on direct connect load that previously faced large increases in charges would be substantially less than indicated by the modelling in the second issues paper, although a PDP for inefficient exit would no longer be available. The resulting reduction in revenue as a result of the cap would increase the residual and thus increase the charges on other load somewhat. In the second issues paper, the Authority modelled the effect of allowing $30 million of PDPs for inefficient exit, which shows the possible impact on the residual from this change.

5.43 If Transpower chose to extend the AoB charge to all pre-guideline investments, the impact could be more substantial. Grid-connected generation would face an increase in AoB charges relative to the proposal in the second issues paper. Overall charges on load would reduce correspondingly and shift from load that most benefited from the post-2004 investments to other load that faced relatively small AoB charges under the proposed guidelines in the second issues paper. However any higher charges customers otherwise faced would be limited by any transition proposed by Transpower.

5.44 For DG, under the DGPP decisions, distributors should continue to charge DG the incremental cost of their connection, so there should be limited impact on DG from the proposed refinements. The exception to this would be DG situated at distribution network locations where they inject into the grid. The impact on such DG would depend on whether distributors pass on transmission charges to them and whether they are located in the South Island and so currently face an HVDC charge. Charges for South Island DG may fall, although this depends on the coverage of the AoB charge and its effect. For North Island DG at locations that result in injections into the grid, they may face AoB charges to the extent they benefit from transmission assets but the impact depends on the coverage and effect of the AoB charge.

5.45 If Transpower chose to extend the AoB charge to some more, but not all pre-guideline investments, the impact would depend on which pre-guideline investments it chose. However, it is likely that charges on at least some generation would increase relative to the second issues paper proposal and the residual would reduce. Any increases in charges on load would be moderated by the cap on charge increases, the reduction in the residual and any transition proposed by Transpower.

5.46 Beyond this, the proposed guidelines would be more durable, because of the cap on charge increases, the ability for Transpower to propose a transition with respect to other pre-guideline investments, the removal of anomalies, the potential reduction in the residual charge arising from any extension of the AoB charge to more pre-guideline investments, and the removal of access to the PDP for inefficient exit.

6 Evaluation of the refinements against the Authority's statutory objective

6.1 The Authority has reviewed its "Evaluation of the proposal against the Authority's Statutory Objective" in the second issues paper in light of the refinements proposed in this supplementary paper. The Authority considers that the refinements of the proposal have little impact on its conclusion there, but to the extent they do, they enhance the proposal's contribution to the statutory objective overall. The Authority therefore remains of the view that:

(a) the proposal as refined promotes the Authority's statutory objective

(b) the proposal outperforms the current TPM and also outperforms the alternatives it has investigated.

6.2 In particular, the refinements modify the discussion in the second issues paper in the following ways:

(a) To the extent that Transpower decides to apply the AoB charge to more historical investments it would reduce the size of the residual charge. As a result, the negative effects of the residual charge discussed in paragraph 10.57 of the second issues paper would be reduced.

(b) If Transpower decides to apply the AoB charge to the bulk of historical investments:

(i) the negative effects of discouraging the use of just some investments, as discussed in paragraph 10.55 of the second issues paper, would be reduced

(ii) the benefits of applying the charge to historical assets discussed in paragraph 10.56 of the second issues paper would be enhanced.

6.3 The Authority is now proposing that the AoB charge for pre-guideline investments as well as post-guideline investments be set using a proxy for replacement cost. As a result, the benefit of using replacement cost for new investments, as discussed in paragraph 10.48 of the second issues paper, would also apply to historical investments. However, since it would be a proxy, the implementation costs would be lower, implying greater net benefits.

6.4 Removing inefficient exit as a criterion for qualifying for a prudent discount means that some of the risks identified in paragraph 10.48 of the second issues paper would be avoided. While it also means that some of the benefits discussed in paragraph 10.21 would not be realised, the Authority's view now is that risks avoided outweigh the potential benefits. The other refinements to the PDP should also be beneficial.

6.5 Because the refinements implement the intent of the Authority's proposal in a more precise and even-handed way, the durability benefits of the proposal discussed in paragraph 10.49 of the second issues paper would be enhanced.

7 Evaluation of the refinements against the Authority's Code Amendment Principles

7.1 The Authority has reviewed its "Evaluation of the proposal against the Authority's Code Amendment Principles" in the second issues paper in light of the refinements proposed in this supplementary consultation paper. The Authority considers that the refinements of the proposal have little impact on its conclusion there, and that the proposal remains consistent with the Authority's Code amendment principles. In particular:

(a) The proposal is lawful.

(b) The proposal (including both the proposal in the second issues paper and the refinements to it outlined in this supplementary paper) will improve efficiency, for the reasons set out in both papers.

(c) Many of the benefits of the proposal have been quantified by OGW. OGW's view is that the refinements do not materially impact on their estimate of the benefits of the proposal other than the proposal to exclude "inefficient exit" from the PDP. (The Authority now considers that the "inefficient exit" proposal has net costs). The Authority broadly accepts this evaluation, although as noted in chapter 4, there may be some reduction in the benefit from avoiding inefficient DG caused by the Authority's decision on the DGPP. In addition, as the second issues paper discusses, the Authority is of the view that the benefits that have not been quantified are likely to be substantial.

(d) The Authority is of the view that it does not need to consider Tiebreaker 1, for the reasons set out in the second issues paper. However, if it were to apply Tiebreaker 1, it would also favour the Authority's proposal, for the reasons set out in the second issues paper.

Appendix A Winter capacity margin– potential effect of recent transmission pricing and distributed generation proposals: paper prepared by Concept Consulting (provided as part of DGPP documents)

Appendix B Oakley Greenwood: Responses to issues raised in submissions

Appendix C Oakley Greenwood: Impact of the proposed changes to the TPM on the CBA

Appendix D The Authority's response to submissions on the CBA, where it is appropriate for the Authority, rather than OGW, to respond

Appendix E Proposed Guidelines

Appendix F TPM supplementary consultation modelling results

Glossary

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, also Pacific Aluminium
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