2019 issues paper

Transmission pricing review

GUIDELINES AND POLICY

Consultation paper

23 July 2019

Appendix A Proposed TPM guidelines

Policy objectives

The Electricity Authority (the **Authority**) has reviewed the guidelines which Transpower is required by the Electricity Industry Participation Code 2010 (the **Code**) to follow in developing a proposed transmission pricing methodology (**proposed TPM**) (the **Guidelines**).

Having undertaken this review, the Authority considers that, in order to allow Transpower to recover up to its forecast maximum allowable revenue in any year and to better meet the Authority's statutory objective, the proposed TPM should contain the following components:

(a) a connection charge;

(b) a benefit-based charge;

(c) a residual charge;

(d) a prudent discount policy;

(e) a cap on transmission charges; and

(f) seven additional components which are to be implemented if they better achieve the Authority's objective.

Connection charge

The purpose of the connection charge is to charge each designated transmission customer to recover the cost of the assets that connect it to the interconnected grid.

Benefit-based charge

The purpose of the benefit-based charge is to recover the costs of new and certain existing investments in the interconnected grid (including investments in transmission alternatives). The charge is to be allocated between designated transmission customers in accordance with the estimated positive net private benefits that each transmission customer is expected to receive from the investment (or a proxy for these benefits). The positive net private benefit of the transmission customer includes the positive net private benefit of any parties that are connected to the interconnected grid through the transmission customer.

Residual charge

The purpose of the residual charge is to provide a mechanism to ensure that Transpower is able to recover up to its forecast maximum allowable revenue in any year in a way which does not affect designated transmission customers' decision-making.

Prudent discount policy

The purpose of the prudent discount policy is to allow Transpower to discount the transmission charges of a designated transmission customer who otherwise would find it viable to inefficiently bypass the grid (including inefficiently disconnecting from the grid in favour of alternative supply).

Cap on transmission charges

The purpose of the cap on certain transmission charges is to minimise price shock by limiting the total increase in transmission charges relating to the existing interconnected grid that each load customer faces relative to the charges that the customer actually pays for the existing interconnected grid in the 2019/20 pricing year. The cap applies only as long as it is effective in limiting a designated transmission customer's transmission charges subject to the price cap as set out in clause 49.

Additional components

Transpower would include each additional component in the TPM if doing so would better achieve the Authority's statutory objective.

(a) Staged commissioning. The purpose of this component is to allow Transpower to adjust how it recovers the cost of an investment that is commissioned in stages, so the charges better reflect the positive net private benefits it provides.

(b) Assets that in substance provide connection services. The purpose of this component is to ensure that if a connection asset that continues in substance to provide principally connection services is reclassified as an investment in the interconnected grid, it is still charged for as a connection asset.

(c) Charges for connection assets. The purpose of this component is to allocate connection charges in substantially the same way as benefit-based charges.

(d) Transitional peak charge. The purpose of this component is to efficiently influence grid use at peak times for a limited transitional period, if nodal prices are not adequate to meet this objective.

(e) Extension of benefit based charge. The purpose of this component is to allow Transpower to extend the benefit based charge to further pre-2019 investments.

(f) Opex. The purpose of this component is to attribute opex to the investment or asset that it is spent on without recourse to proxies.

(g) kvar charge. The purpose of this component is to allow Transpower to impose a charge on reactive power.

General matters

1. In developing the **TPM** in accordance with these **Guidelines**, Transpower must, as far as reasonably practicable:

   (a) set charges in a way that reflects:

   (b) the cost of providing designated transmission customers with:

      A. new investment in the grid;

      B. access to the parts of the grid relevant to them; and

      C. use of the grid to transport energy;

   (ii) the **positive net private benefits** those designated transmission customers derive from those things;

   (c) balance the economic benefits and costs of precision of the **TPM** with the economic benefits and costs of practical considerations including:

      (i) robustness;

      (ii) simplicity;

      (iii) certainty, including through limiting the need for Transpower to exercise a discretion; and

(iv) costs associated with developing, administering and complying with the **TPM**;

(d) avoid creating incentives for existing and potential designated transmission customers to avoid **transmission charges** in ways that cause economic inefficiency;

(e) avoid creating incentives for distributed generators to seek avoided cost of transmission payments, except to the extent that the payments reflect a saving in the costs of transmission (not just a saving in **transmission charges** to the relevant distributor);

(f) avoid discriminating between designated transmission customers, except to the extent necessary to achieve the Authority's statutory objective; and

(g) allow Transpower to recover its **forecast MAR**, should it wish to do so.

2. Transpower may propose a **TPM** which differs in its details from the particular requirements in the **Guidelines**, if it considers, in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with the **Guidelines** in their entirety.

3. All subsequent provisions in these **Guidelines** are to be interpreted and applied subject to clauses 1 and 2 above.

4. In developing the **TPM**, Transpower must prepare an outline of Transpower's reasons for proposing the particular methods it has included in the **TPM**, to be provided to the Authority along with the **TPM**. This outline must include details of:

(a) where, under clause 2, Transpower proposes a **TPM** which differs in its details from the particular requirements of the Guidelines, how the **TPM** differs from the **Guidelines** and Transpower's reasons for proposing a **TPM** which differs from the **Guidelines**, including why it considers that its proposed **TPM** better meets the Authority's statutory objective; and

(b) where Transpower has made an assumption in developing the **TPM**, the assumption made and Transpower's reasons for making that assumption.

5. The **TPM** must include requirements for Transpower to consult on:

(a) the proposed **benefit-based charge** and its allocation between designated transmission customers for each proposed **high-value benefit-based investment**;

(b) the proposed allocation of the **residual charge**;

(c) important parameters used to calculate those charges and allocations;

(d) any proposed material changes to those charges or allocations (in which case consultation must extend to whether such changes are warranted by a change in circumstances); and

(e) any assumptions made in calculating those charges, allocations or material changes to those charges or allocations,

with parties who have a material financial interest in the charges. Where Transpower can demonstrate that such parties have already been consulted on the above (whether by Transpower or any other party), it need not repeat that consultation for the purposes of this clause.

6. The **TPM** must include a requirement for Transpower to provide each designated transmission customer with information regarding how its **transmission charges** have been calculated, including the basis on which its **benefit-based charge** and **residual charge** have been set. The basis on which the **residual charge** has been set includes the extent to which the **residual charge** comprises unallocated **opex** and the extent to which it comprises costs which have been reallocated to the **residual charge** as a result of **benefit-based investments** having been subject to **reassignment**. Information provided for the purposes of this clause should be sufficient to enable the designated transmission customer to verify the accuracy of Transpower's calculations of its **transmission charges**.

7. The **TPM** must provide that, where it is necessary to consider the characteristics of, benefits or costs accruing to, or incentives on, a designated transmission customer under the **TPM**, that assessment must also consider the characteristics of, benefits or costs accruing to, or incentives on any parties directly or indirectly electrically connected to that designated transmission customer.

8. The **TPM** must provide for the treatment of a transmission alternative to be consistent with the treatment the investment which the transmission alternative seeks to avoid would have received under these **Guidelines** or, where this is not reasonably practicable, for the cost of transmission alternatives to be allocated to the designated transmission customers that benefit from them in proportion to the relative level of benefit that each customer receives.

Main components

9. The **TPM** must include:

    1. a charge for **connection assets**;
    2. a **benefit-based charge**;
    3. a **residual charge**;
    4. a prudent discount policy; and
    5. a cap on specified **transmission charges**.

    The total recovered by Transpower under these components may not exceed Transpower's **forecast MAR**.

Main component 1: connection charge

10. The **TPM** must provide for the costs of **connection assets** to be recovered from those connected to them.

11. The **TPM** must include a definition of deep connection, which must be applied consistently and transparently. The definition of deep connection must avoid subsidisation of interconnection assets to the extent reasonably practicable.

Main component 2: benefit-based charge

Benefit-based charge must apply to benefit-based investments

12. The **TPM** must include a **benefit-based charge** for each **benefit-based investment**.

13. A **benefit-based investment** means:

(a) any **post-2019** investments in the **interconnected grid**, including any transmission alternatives;

(b) the following **pre-2019** investments in the **interconnected grid:**

(i) the Bunnythorpe-Haywards Reconductoring Project

(ii) investments in and associated with the HVDC link

(iii) the Lower South Island Renewables Project;

(iv) the Lower South Island Reliability Project;

(v) the North Island Grid Upgrade (NIGU) Project;

(vi) the Upper North Island Dynamic Reactive Support Project; and

(vii) the Wairakei Ring Project;

(c) **upgrading expenditure** as provided for in clauses 30 to 32 below; and

(d) **pre-2019** investments in the **interconnected grid** identified by means of a method established under clauses 62 and 63 below**.**

Benefit-based charges must recover the covered cost of benefit-based investments

14. The **benefit-based charge** for a **benefit-based investment** must recover, over the **benefit-based investment's remaining life**, the present value of the **covered cost** of that **benefit-based investment**, which comprises:

(a) the capital cost of the **benefit-based investment**, based on:

(i) for **post-2019 benefit-based investments**, the **value of commissioned assets** forming part of that **benefit-based investment**;

(ii) for **pre-2019 benefit-based investments**, the depreciated value of the assets comprising the **benefit-based investment** as recorded in the **regulatory asset base** at the date the **benefit-based charge** is first applied to the **benefit-based investment**;

(b) a return on capital for the **benefit-based investment**, based on its capital cost as allowed for under paragraph (a) and **WACC**;

(c) an amount of forecast **opex** reasonably attributable to the benefit-based investment based on an allocation of the **opex** allowance for the **pricing year** as set by the Commerce Commission in the **IPP**; and

(d) any other costs attributable to that **benefit-based investment**.

Recovery of the covered cost of a benefit-based investment over time

15. The **TPM** must provide for the **annual benefit-based charges** for each **post-2019 benefit-based investment** to be calculated:

    (a) using the following method:

        (i) the expected **benefit-based charge** for the **benefit-based investment** is divided into equal annual amounts over the **benefit-based investment's remaining life**; and
        (ii) the annual amounts determined under subclause (a)(i) are adjusted for inflation over the **benefit-based investment's remaining life** using an index determined by Transpower; or

    (b) according to an alternative method, where that alternative method:

        (i) would better meet the Authority's statutory objective than the method described in paragraph (a); and

        (ii) would still recover the **covered cost** of that **benefit-based investment**.

16. The **TPM** must provide that Transpower's recovery of the capital components for each **pre-2019 benefit-based investment** for a **pricing year** under the **TPM** must be the same as the forecast depreciation and forecast capital charge in that **pricing year** for the assets of that **benefit-based investment** under the **IPP**.

17. The **TPM** must allow Transpower to adjust future **annual benefit-based charges** for a **benefit-based investment** if, in Transpower's reasonable assessment, there has been, or will be, a material change to any of the expected future:

    (a) **WACC**;

    (b) **opex** attributable to the **benefit-based investment**;

    (c) **remaining life** of the **benefit-based investment**; or

    (d) any other costs attributable to the **benefit-based investment**.

    The **benefit-based charge** must recover the present value of the **covered cost** of each **benefit-based investment**.

Damage to a benefit-based investment

18. The **TPM** must allow Transpower to adjust or end future **annual benefit-based charges** for a **benefit-based investment** where an asset or assets forming part of that **benefit-based investment** are destroyed or substantially damaged.

Allocating annual benefit-based charges among customers

19. The **TPM** must include one or more standard methods for allocating **annual benefit-based charges**.

20. The **TPM** may include one or more simple methods for allocating **annual benefit-based charges**.

21. The **TPM** must provide:

    (a) that Transpower must use a standard method to allocate the **annual benefit-based charges** for **high-value post-2019 benefit-based investments**;

    (b) that Transpower must use Schedule 1 to allocate the **annual benefit-based charges** for the **benefit-based investments** included in Schedule 1;

    (c) where these **Guidelines** provide for an adjustment to the Schedule 1 allocations, a method for making that adjustment. That method must be a standard method, simple method or combination of both; and

    (d) that Transpower must use a standard method, simple method or combination of both to allocate the **annual benefit-based charges** for any other **benefit-based investments**.

22. A standard method:

    (a) must allocate the **annual benefit-based charge** for a **benefit-based investment** between the designated transmission customers expected to benefit from the **benefit-based investment** in proportion to their expected **positive net private benefit** from the **benefit-based investment** over its **remaining life**;

    (b) where necessary, may determine expected **positive net private benefits** using one or more reasonable proxies. Such proxies must, in Transpower's reasonable opinion, result in an allocation of the **benefit-based charge** to each designated transmission customer who receives a major **positive net private benefit** from the **benefit-based investment** that broadly approximates the allocation that Transpower considers would have resulted had expected **net private benefits** been used to calculate the allocation.

23. A simple method:

    (a) must be capable of being implemented at a lower cost to participants, including Transpower, than the standard method(s). Cost includes administrative burdens on participants but does not include increases in resulting **transmission charges**;

    (b) must, in Transpower's reasonable opinion, result in an allocation of the **benefit-based charge** to the designated transmission customers who receive a major **positive net private benefit** from the **benefit-based investment** that broadly approximates the allocation that Transpower considers would have resulted had the standard method been applied. However, Transpower is not required to apply the standard method solely for the purpose of making this assessment; and

    (c) may exempt designated transmission customers who do not receive a major **positive net private benefit** from a **benefit-based investment** from receiving an allocation of the **annual benefit-based charges** for the **benefit-based investment**.

24. The **TPM** must provide that, save for benefits and costs included at Transpower's discretion, the treatment of benefits and costs used to calculate **net private benefits**, to the extent applicable, in respect of **post-2019 benefit-based investments** under each standard method and each simple method must be consistent with, though not necessarily identical to, the treatment of the relevant **electricity market benefit or cost elements** under the test used by the Commerce Commission in its approval of the **post-2019 benefit-based investment**, unless Transpower considers there has been a material change since that test was applied.

25. The **TPM** must provide that, once a designated transmission customer's share of the **annual benefit-based charge** has been allocated, that share will not change, save where these **Guidelines** permit otherwise.

26. The **TPM** must provide:

(a) that Transpower may review the allocation of future **annual benefit-based charges** for a **high-value benefit-based investment** if Transpower considers there has been, or expects that there will be, a substantial and sustained change in grid use affecting the **net private benefits** derived by one or more designated transmission customers from the **benefit-based investment**;

(b) that a substantial change in grid use will only have occurred where the circumstances which have eventuated were not factored into the calculations used to allocate the relevant charges;

(c) a method for Transpower to determine whether there has been a substantial and sustained change in grid use affecting a **high-value benefit-based investment**; and

(d) a method/s for adjusting allocations in the event that there has been a substantial and sustained change in grid use.

Implementation timeframe for the benefit-based charge

27. The **TPM** must provide for the **benefit-based charge** to apply to **high-value post-2019 benefit-based investments** and **pre-2019 benefit-based investments** to which Schedule 1 applies from the commencement of the **TPM** or the date on which the investment is **commissioned** (whichever is later).

28. The **TPM** must provide for **benefit-based charges** for **low-value post-2019 benefit-based investments** to be phased in as soon as is reasonably practicable after the **benefit-based charge** has been applied to the **high-value benefit-based investments** listed in clause 27 and no later than five years after the commencement of the **TPM**.

29. The **TPM** must provide that the implementation of **additional components**, other than a transitional **peak charge**, must be deferred if necessary in order to expedite the implementation of the **benefit-based charge** for **high-value benefit-based investments**.

Upgrading expenditure

30. **Upgrading expenditure**, in relation to existing **benefit-based investments**, means expenditure that results in an extension to the existing **benefit-based investment's remaining life** or otherwise increases the benefits that **benefit-based investment** is expected to provide.

31. The **TPM** must provide that, where Transpower undertakes **upgrading expenditure**, that **upgrading expenditure** must be recovered using the method prescribed in these **Guidelines** for recovering the **covered cost** of a **post-2019 benefit-based investment** having a capital cost equal to the cost of the **upgrading expenditure**.

32. Subject to clause 31, in recovering **upgrading expenditure** on existing **benefit-based investments**, Transpower may:

(a) treat the **upgrading expenditure** as a new **benefit-based investment**; or

(b) adjust as appropriate the value of the **benefit-based investment**, its **remaining life**, its estimated benefits and the calculation and allocation of the **annual benefit-based charge** for it, in order to reflect the changes caused by the **upgrading expenditure.** An adjustment under this paragraph may alter the **covered cost** and allocation for the overall **benefit-based investment** (comprising the initial **benefit-based investment** and the **upgrading expenditure**). However, such an adjustment is not to alter the requirement to recover the **covered cost** of the initial **benefit-based investment** or the calculation of **net private benefits** for the initial **benefit-based investment**.

Reassignment

33. The **TPM** must provide for a party to make an application to Transpower for **reassignment** of charges:

    (a) where that party has a direct or indirect financial interest in the **annual benefit-based charge** for that **benefit-based investment**;

    (b) where the **benefit-based investment** had an initial value of $5 million or more (with this threshold to be adjusted for inflation); and
    (c) whether or not the **benefit-based investment** has previously been subject to **reassignment**.

34. The **TPM** must provide that a **benefit-based investment** must, and may only, be subject to **reassignment** if Transpower considers that the circumstances which led to the **reassignment** are likely to be sustained and:

    (a) for a **pre-2019 benefit-based investment**, the investment's value following **reassignment** would be less than 80% of its current value;

    (b) for a **post-2019 benefit-based investment**:

        (i) where the disconnection of a single party causes the **benefit-based investment's** value following **reassignment** to be less than 80% of its current value; or
        (ii) the **benefit-based investment** has been **commissioned** or otherwise been in operation for the period of time specified in the **TPM** for the purpose of this subclause and its value following **reassignment** is now less than 80% of its current value.

35. In setting a period of time for which a **post-2019 benefit-based investment** must have been **commissioned** in order for it to be eligible for **reassignment**, the **TPM** must provide for that period to be sufficiently long that the prospect of **reassignment** will likely have a negligible impact on the characteristics of the **post-2019 benefit-based investment** that designated transmission customers are incentivised to seek.

36. The **TPM** must include a method for determining the value of a **benefit-based investment** following **reassignment** which is consistent with the revision to forecast future demand for **transmission lines services** which gave rise to the **reassignment**.

37. The **TPM** must provide that, where Transpower determines that the circumstances which led to the **reassignment** no longer exist, it must reverse the **reassignment** (that is, restore the value of the **benefit-based investment** to the value that would have applied if the **reassignment** had not taken place) or adjust the level of the **reassignment**, as is appropriate.

38. The **TPM** must provide that, where Transpower determines to carry out **reassignment** with respect to a **benefit-based investment** or reverse a **reassignment**, it must:

    (a) modify the **annual benefit-based charge** for that investment to take into account the change in the **benefit-based investment's** value;

    (b) adjust the allocation of the **annual benefit-based charge** to designated transmission customers to the extent necessary to take into account the change in forecast future demand for **transmission lines services** which led to the **reassignment** or reversal of the **reassignment**; and

    (c) adjust the **residual charge** as necessary to take into account the changes to the **annual benefit-based charge**.

Main component 3: residual charge

39. The **TPM** must provide for a **residual charge** to apply to all designated transmission customers to the extent that they are load to recover any remaining **forecast MAR** not recovered through other **transmission charges**.

40. The **TPM** must provide for the **residual charge** to be allocated:

(a) in proportion to each designated transmission customer's historical anytime maximum demand, which is to be calculated using data supplied by the reconciliation manager and by:

(i) taking, in a **pricing year**, the highest value for any trading period which represents the sum of:

A. the highest net quantity of electricity flow from the grid at the designated transmission customer's grid exit point; and

B. Transpower's estimate of any concurrent generation by distributed generators or behind-the-meter generation that is indirectly connected to the grid through the designated transmission customer; and

(ii) taking the average of that value over at least two years ending prior to either 1 July 2019 or the date 10 years prior to the date on which the **residual charge** is to be assessed, whichever is the later; or

(b) by an alternative method of allocating the charge to designated transmission customers to the extent that they are load, should Transpower consider that the alternative method would better meet the Authority's statutory objective than the method set out in paragraph (a) above.

41. The **TPM** must provide that, in initially allocating the **residual charge** under clause 40, Transpower may adjust the allocation where necessary to accommodate circumstances in which a designated transmission customer has experienced a substantial change in demand due to factors beyond their control or influence. For the purposes of this clause, a substantial change in demand is to be assessed relative to the designated transmission customer's remaining demand.

Provisions relating to adjustments

42. The **TPM** must:

(a) provide for a process for allocating **benefit-based charges** and **residual charges** in respect of:

(i) new **large consumers or generators**;

(ii) existing **large consumers or generators** who establish a new plant or generating unit or increase (where that increase is substantial and sustained) an existing plant's electricity use or an existing generating unit's generation, where that plant or generating unit is directly or indirectly connected to the grid;

(b) provide that, where a designated transmission customer sells part of its business, Transpower may allocate the designated transmission customer's charges between the original and new owners; and

(c) avoid creating inefficient incentives for a **large consumer or generator** to shift their point of connection (beyond the ability to do so in the prudent discount policy). The prudent discount policy may apply to circumstances where a **large consumer or**

generator is considering shifting their point of connection, but the **TPM** must include additional provisions to avoid creating such incentives.

The charges may need to be scaled back

43. The **TPM** must provide for the charges set under it to be scaled back if, in any **pricing year**:
    (a) applying the other provisions of the TPM would result in Transpower recovering more than its **forecast MAR**; or

    (b) Transpower wishes to recover less than its **forecast MAR**.

44. The **TPM** must provide that, where clause 43(a) applies, charges are to be scaled back in the following order:

    (a) the **residual charge**;

    (b) the **annual benefit-based charge** for **pre-2019 benefit-based investments**; then

    (c) the **annual benefit-based charge** for **post-2019 benefit-based investments**.

45. The **TPM** must provide that, where clause 43(b) applies, Transpower may first scale back the **annual benefit-based charge** for a **benefit-based investment**. However, such a scaling back of the **annual benefit-based charge** must not result in an increase to the **residual charge**.

Main component 4: prudent discount policy

46. The **TPM** must provide for a prudent discount policy that encourages designated transmission customers not to inefficiently bypass the grid, including encouraging **load customers** not to inefficiently disconnect from the grid in favour of alternative supply.

47. The prudent discount must be available where a designated transmission customer can establish that:

    (a) it would be technically and operationally feasible, and commercially beneficial, for the designated transmission customer to undertake the relevant action described in clause 46; and

    (b) the relevant action would be inefficient to implement given Transpower's economic costs of providing the designated transmission customer with access to the **interconnected grid** and the economic costs incurred by the designated transmission customer if it proceeded with the relevant action described in clause 46.

48. The prudent discount must apply for the **remaining life** of the relevant investment, unless Transpower and the party receiving the prudent discount agree to a different period.

Cap on transmission charges

49. Subject to clause 53, the **TPM** must provide for a price cap on each **load customer's** total **transmission charges** excluding:

    (a) any **connection charge**;

    (b) any **peak charge**;

    (c) any kvar charge;

    (d) any charge attributable to investments commissioned or otherwise entering into operation after the end of the 2019/20 **pricing year**;

(e) any **benefit-based charge** in respect of any **pre-2019 benefit-based investment** identified by means of a method established under clauses 62 and 63;

(f) any increase in the **residual charge** due to a **reassignment** of a **benefit-based investment**;

(g) any increase in a designated transmission customer's allocation of the **annual benefit-based charge** for a **benefit-based investment** due to a reallocation under clause 26; and

(h) the application of clause 42.

50. Subject to clause 53, in setting a price cap, the **TPM** must provide for:

(i) any increase in a distributor's **transmission charges** subject to the price cap as set out in clause 49, as compared to its **transmission charges** minus its connection charges in the 2019/20 **pricing year**, to be limited to no more than the amount resulting from the following formula:

$$B \times (0.035 + CPI + L)$$

where:

B is Transpower's estimate of the total electricity bill for all consumers supplied, directly or indirectly, from the distributor's network in the 2019/20 **pricing year** (expressed in dollars), calculated as:

$$B = C + P*V$$

and where

CPI is the change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal);

L is the increase in the distributor's load since the 2019/20 **pricing year**, if any (expressed as a decimal);

C is the distributor's total line charge revenue for the 2019/20 **pricing year** excluding GST from Schedule 8 Report on Billed Quantities and Line Charges Revenues of the Electricity Distribution Information Disclosure Determination 2012;

P is the volume weighted average of wholesale energy prices at the distributor's grid exit point or points for the 5 years up to and including the 2019/20 **pricing year** from the Authority's Electricity Market Information database, expressed in $/MWh and excluding GST, with weights being the gross load as determined by the reconciliation manager; and

V is the distributor's total gross load for the 2019/20 **pricing year**, expressed in MWh, as determined by the reconciliation manager;

(j) any increase in a direct consumer's **transmission charges** subject to the price cap as set out in clause 49, as compared to its **transmission charges** minus its connection charges in the 2019/20 **pricing year**, to be limited to no more than:

$$B \times (0.035 + 0.02 \times Y + CPI + L)$$

where:

B is Transpower's estimate of the total electricity bill of that direct consumer in the 2019/20 **pricing year** (expressed in dollars), calculated as;

$$B = T + P*V$$

and where

Y is the greater of zero and of the number of **pricing years** which have elapsed since the 2019/20 **pricing year** minus 5;

CPI is the change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal);

L is the increase in the direct consumer's load since the 2019/20 **pricing year**, if any (expressed as a decimal);

T is what the direct consumer's total **transmission charge** (including any **connection charge**) is or would have been under the existing **TPM** in the 2019/20 **pricing year**, excluding GST;

P is the volume weighted average of wholesale energy prices at the direct consumer's grid exit point or points for the 5 years up to and including the 2019/20 **pricing year** from the Authority's Electricity Market Information database, expressed in $/MWh and excluding GST; and

V is the total direct consumer's load in the 2019/20 **pricing year** in MWh, such information to be obtained from the reconciliation manager; and

(k) the price cap to be permanently removed for a particular **load customer** if, in any **pricing year** after the **pricing year** in which **benefit-based charges** are first applied to **low-value post-2019 benefit-based investments**, the cap does not have the effect of reducing the **load customer's transmission charges** subject to the price cap as set out in clause 49.

51. To the extent that the price cap results in a reduction in **transmission charges** for one or more **load customers**, the revenue so forgone is to be recovered by a surcharge on and proportional to the total of the **benefit-based charge** for the investments listed in clause 13(b) and the **residual charge** for each designated transmission customer.

52. The surcharge on the **benefit-based charge** and the **residual charge** for a designated transmission customer is to be reduced if necessary and to the extent necessary to ensure that its **transmission charges** subject to the price cap as set out in clause 49 meet the condition in clause 50.

53. The price cap provisions must not prevent Transpower from recovering its **forecast MAR**.

Additional components

54. The **TPM** must incorporate each of the following **additional components**, where including that component would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**:

(a) staged commissioning, as described in clause 55;

(b) charges for assets principally providing connection services, as described in clause 56;

(c) charges for connection assets, as described in clause 57;

(d) a transitional peak charge, as described in clauses 58 to 61;

(e) including additional pre-2019 investments in the benefit-based charge, as described in clauses 62 and 63;

(f) charging for **opex**, as described in clause 64; and

(g) a kvar charge, as described in clause 65.

Additional component A: staged commissioning

55. This component must provide a method for Transpower, at its discretion, to adjust the time profile and allocation of charges over a **benefit-based investment's remaining life** where an investment is **commissioned** in stages so that it sometimes meets the definition of a **connection asset**, in order to best reflect the benefits provided while it is a connection investment relative to the benefits provided after it has become an investment in the **interconnected grid**. The **benefit-based charge** must recover the present value of the **covered cost** of each **benefit-based investment**, less any **connection charges** already paid.

Additional component B: charges for assets principally providing connection services

56. This component must provide a method to ensure that charges that apply to assets that provide connection services are not affected by connecting those assets to other assets, if they continue to provide principally the services of a **connection asset**, notwithstanding that they do not meet the formal definition of a **connection asset**.

Additional component C: charges for connection assets

57. This component must provide for the method for determining the annual amount to be recovered for each new **connection asset** to align with the method for determining the **annual benefit-based charge** for **post-2019 benefit-based investments**, notwithstanding the requirements of clauses 10 and 11.

Additional component D: transitional peak charge

58. This component must provide a method for determining, in respect of the transitional **peak charge**:

(a) the initial level of the charge;

(b) the designated transmission customers or geographic areas to, or the circumstances in, which it applies; and

(c) how the charge is to be allocated between designated transmission customers.

The transitional **peak charge** may only apply in respect of those geographic areas, circuits or other circumstances which, in Transpower's reasonable opinion, would experience congestion without a transitional **peak charge**.

59. If Transpower determines to include a transitional **peak charge** in the **TPM**, it must include in its outline required under clause 4 of these **Guidelines**, an explanation as to why it considers that grid demand will not be adequately controlled by the other prices including nodal pricing.

60. If the **TPM** includes a transitional **peak charge**:

(a) the transitional **peak charge** must be progressively phased out, such phase-out to commence no later than one year after the transitional **peak charge** is first imposed;

(b) the phase-out of the transitional **peak charge** must result in it being phased out completely within five years of the **TPM** entering into effect. Transpower may, during this phase-out period, temporarily pause the phase-out or increase the transitional **peak charge**, including by reinstating a transitional **peak charge** which has already been phased out, where doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective, provided that the phase-out is still completed within the five year period unless Transpower has obtained the Authority's approval under paragraph (d) below to extend that period;

(c) the **TPM** must include the process for phasing out the transitional **peak charge**, including specifying the maximum transitional **peak charge** which can be levied in any year, which may be expressed as a percentage of the initial transitional **peak charge**; and

(d) the **TPM** must include provision for Transpower to apply to the Authority during the phase-out period, to deviate from the maximum transitional **peak charge** that may be levied in any year, the time limit on or duration of the phase-out period. Transpower must provide to the Authority such information as the Authority requires to determine an application under this paragraph.

61. Notwithstanding anything in clause 60 above, after the phase-out period has ended, Transpower may propose to reinstate or introduce a new transitional **peak charge** as part of a review under clause 12.85 of the **Code**. In proposing a reinstated or new transitional **peak charge**, Transpower must provide to the Authority such information as the Authority requires to assess Transpower's proposal.

Additional Component E: Including additional pre-2019 investments in the benefit-based charge

62. This component must include a method for extending the definition of **benefit-based investment** to other **pre-2019 benefit-based investments** in the **interconnected grid** and related services, including transmission alternatives, that contribute to Transpower's **forecast MAR**.

63. If the **TPM** includes such a method, it:

(a) must specify a method for allocating the **annual benefit-based charges** for the **benefit-based investments** between designated transmission customers. The method must be a simple method as described in clause 23;

(b) must provide for the **benefit-based charge** for such **benefit-based investments** to be capped at the present value of the aggregate **positive net private benefits** expected to be derived by designated transmission customers from the **benefit-based investment** over its **remaining life**; and

(c) may include transitional provisions which phase in the relevant charges.

Additional component F: charging for opex

64. This component must include a method for allocating **opex** expended in relation to **connection assets** and assets in a **benefit-based investment** to the designated transmission customers paying charges in relation to that asset or investment. The method must not use a proxy or generalised rule for allocation.

Additional component G: kvar charge

65. This component must include a method for imposing a kvar charge on reactive power.

Interpretation

66. In these **Guidelines**, unless the context otherwise requires it:

2019 Issues Paper means the issues paper prepared by the Authority under clause 12.81 of the **Code** and published by the Authority on [**date**] 2019.

additional component means one of the components required by clause 54 of these **Guidelines** to be included in the **proposed TPM** where Transpower considers that including that component will better meet the Authority's statutory objective than not including it.

annual benefit-based charge means the amount of the **benefit-based charge** to be recovered in respect of a particular **benefit-based investment** in any one **pricing year**.

asset refurbishment has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time.

asset replacement has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time.

benefit-based charge means the charge as described in clause 12.

benefit-based investment has the meaning given to it in clause 13.

Code means the Electricity Industry Participation Code 2010, as amended from time to time.

commissioned has the meaning given to it in the Commerce Commission's *Transpower Input Methodologies Determination 2010* [2012] NZCC 17, as amended from time to time.

connection assets means the assets owned by Transpower used to connect a designated transmission customer to the grid**,** and may have a more precise definition in the **transmission pricing methodology** as amended from time to time.

connection charge means the charge described in clauses 10 and 11.

covered cost, in relation to an **benefit-based investment**, has the meaning given to it in clause 14.

electricity market benefit or cost element has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination 2012* [2012] NZCC 2, as amended from time to time*.*

forecast MAR means, for a **pricing year**, Transpower's forecast maximum allowable revenue as set by the Commerce Commission in the **IPP**, as amended from time to time. The **IPP** for the **pricing year** commencing 1 April 2010 is the *Transpower Individual Price-Quality Path Determination 2020.*

generation customer means a designated transmission customer that is a generator.

Guidelines means these guidelines.

high-value, in respect of a **benefit-based investment**, means a **benefit-based investment** that, at the time it was first **commissioned** exceeded the "base capex threshold" as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time, whether or not the investment would otherwise meet the test for "major capex".

interconnected grid means the grid including the HVDC link but excluding **connection assets.**

IPP means Transpower's individual price-quality path determined by the Commerce Commission under Part 4 of the Commerce Act 1986 from time to time. At the date of these **Guidelines** the relevant determination is the *Transpower Individual Price-Quality Path Determination 2015.*

large consumer or generator means an actual or potential user of **transmission lines services** (whether as load or generation) which could reasonably contemplate shifting its point of connection.

load customer means a designated transmission customer that is a distributor or direct consumer.

low-value means, in respect of a **benefit-based investment**, a **benefit-based investment** which does not meet the definition for a **high-value benefit-based investment.**

net private benefit means, for a designated transmission customer:

(a) the value of the private benefits which are consistent with **electricity market benefit or cost elements** that arise from the **benefit-based investment** in respect of that designated transmission customer from the commencement date of the **TPM**; less

(b) the value of the private costs which are consistent with **electricity market benefit or cost elements** (but excluding the cost of the **benefit-based investment** itself) that arise from that **benefit-based investment** in respect of that designated transmission customer from the commencement date of the **TPM**,

provided that Transpower may, at its discretion, include as part of the calculation the value of other benefits or costs where those benefits or costs are substantial and result from the **benefit-based investment.**

opex means "operating cost" as defined in the Commerce Commission's *Transpower Input Methodologies Determination 2010*, as amended from time to time.

peak charge means a charge, over and above nodal prices and the other **transmission charges** provided for in these **Guidelines**, imposed to influence peak demand for use of the grid.

positive net private benefit means for a designated transmission customer:

(a) the **net private benefit** if it is positive; or

(b) zero if it is not

post-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is first **commissioned** after the publication of the **2019 Issues Paper** (including any part of a **pre-2019 benefit-based investment** to the extent that it is **commissioned** after this date) and which at the relevant time of **commissioning** constitutes base capex or major capex as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.

pre-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is **commissioned** on or before the date of publication of the **2019 Issues Paper** and which at the relevant time of **commissioning** would have constituted base capex or major capex as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.

pricing year has the meaning given to it in the **IPP.**

reassignment means a reassignment of charges from the **benefit-based charge** to the **residual charge** due to a reduction in the value of an asset for the purposes of the **benefit-based charge**, and **reassignments** and **reassigned** have equivalent meanings.

regulatory asset base means, for a **pricing year**, the asset base used to determine **forecast MAR** for the **pricing year.**

remaining life means, for a **benefit-based investment**, the **benefit-based investment's** expected economic life at the time the relevant clause of the **TPM** applies.

residual charge means the charge as described in clause 39.

TPM means the transmission pricing methodology.

transmission lines services has the meaning given to it in the **IPP.**

transmission charges means the charges provided for by the **TPM**, as amended from time to time.

upgrading expenditure has the meaning given to it in clause 30.

value of commissioned assets has the meaning given to it in the Commerce Commission's *Transpower Input Methodologies Determination 2010* [2012] NZCC 17, as amended from time to time.

WACC means, for a **pricing year**, the pre-tax nominal weighted average cost of capital used to determine **forecast MAR** for the **pricing year.**

67. In these **Guidelines**, unless the context requires otherwise, any other term that is defined in Part 1 of the **Code**, and used but not defined in these **Guidelines**, has the same meaning as in Part 1 of the **Code**. Terms defined in Part 1 of the **Code** are underlined in these **Guidelines**.

Q9. What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?

Schedule 1 Annual benefit-based charges for the benefit-based investments

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive
Alpine Energy	3.11%	0.85%	1.49%	2.98%	0.30%	0.24%	0.30%
Aurora Energy	5.71%	1.57%	0.90%	4.48%	0.30%	0.27%	0.30%
Beach Energy Resources (Kupe)	0.03%	0.07%	0.10%	0.08%	0.03%	0.04%	0.03%
Buller Electricity	0.27%	0.08%	0.12%	0.20%	0.03%	0.02%	0.03%
Centralines	0.07%	0.21%	0.24%	0.17%	0.05%	0.01%	0.05%
Contact Energy	2.11%	12.55%	23.98%	0.09%	5.96%	21.25%	5.96%
Counties Power	0.32%	1.06%	1.08%	0.85%	2.62%	1.41%	2.62%
Daiken Southland	0.28%	0.09%	1.38%	0.28%	0.02%	0.02%	0.02%
Eastland Network	0.17%	0.35%	0.56%	0.41%	0.05%	0.00%	0.05%
Electra	2.70%	0.79%	0.95%	0.67%	0.16%	0.14%	0.16%
Electricity Ashburton	1.70%	0.51%	0.76%	1.71%	0.26%	0.15%	0.26%
Electricity Invercargill	2.26%	0.59%	0.27%	2.19%	0.14%	0.12%	0.14%
Electricity Southland	0.12%	0.04%	0.05%	0.07%	0.01%	0.01%	0.01%
Genesis Power	1.22%	3.23%	0.00%	0.03%	3.66%	7.64%	3.66%
Horizon Energy	0.31%	0.36%	0.59%	0.66%	0.05%	0.00%	0.05%
MainPower	3.21%	0.88%	1.28%	2.95%	0.24%	0.20%	0.24%
Marlborough Lines	2.03%	0.45%	0.87%	1.87%	0.15%	0.12%	0.15%
Mercury	0.62%	0.00%	0.00%	0.00%	6.14%	10.53%	6.14%
Meridian	0.23%	33.70%	1.10%	0.05%	7.35%	0.00%	7.35%
Methanex	0.03%	0.06%	0.09%	0.07%	0.03%	0.04%	0.03%
Nelson Electricity	0.28%	0.06%	0.12%	0.23%	0.02%	0.02%	0.02%
Network Tasman	3.06%	0.71%	1.42%	2.57%	0.22%	0.18%	0.22%
Network Waitaki	1.13%	0.36%	0.52%	2.16%	0.13%	0.08%	0.13%
New Zealand Rail	0.04%	0.07%	0.10%	0.08%	0.20%	0.12%	0.20%
Nga Awa Purua JV	0.00%	0.00%	0.00%	0.00%	0.97%	8.00%	0.97%
Ngatamariki Geothermal	0.01%	0.00%	0.00%	0.00%	0.59%	4.86%	0.59%
Norske Skog	0.00%	0.00%	0.00%	0.00%	0.18%	2.47%	0.18%
Northpower	0.67%	1.13%	2.16%	1.78%	5.98%	2.90%	5.98%

Nova	0.10%	0.00%	0.00%	0.00%	0.21%	0.00%	0.21%
NZ Steel	0.30%	0.50%	0.96%	0.85%	2.47%	1.33%	2.47%
NZ Aluminium Smelters	22.04%	7.25%	2.12%	23.59%	1.61%	1.61%	1.61%
Orion	18.22%	4.88%	7.16%	14.69%	1.15%	1.00%	1.15%
OtagoNet JV	1.46%	0.41%	2.01%	2.03%	0.11%	0.11%	0.11%
Pan Pacific Forest Products	0.35%	0.47%	0.76%	0.69%	0.10%	0.00%	0.10%
Port Taranaki	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Powerco	4.02%	6.25%	8.55%	6.70%	1.91%	3.58%	1.91%
Resolution Developments	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Scanpower	0.05%	0.15%	0.17%	0.12%	0.03%	0.03%	0.03%
Southdown Generation	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.01%
Southern Generation	0.09%	0.01%	0.02%	0.16%	0.07%	0.64%	0.07%
Southpark Utilities	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
The Lines Company	0.16%	0.36%	0.47%	0.37%	0.18%	0.49%	0.18%
The Power Company	1.54%	0.34%	8.22%	2.04%	0.13%	0.12%	0.13%
Tilt Renewables	0.26%	0.01%	0.00%	0.00%	0.16%	0.00%	0.16%
Todd Generation Taranaki	0.24%	0.09%	0.00%	0.01%	0.26%	0.00%	0.26%
Top Energy	0.00%	0.24%	0.00%	0.00%	1.09%	0.51%	1.09%
TrustPower	0.01%	0.75%	0.00%	0.01%	0.16%	1.14%	0.16%
Tuaropaki Power	0.08%	0.06%	0.08%	0.07%	0.68%	0.13%	0.68%
Unison Networks	0.63%	1.34%	2.19%	1.60%	0.16%	0.00%	0.16%
Vector	5.51%	10.76%	18.95%	14.37%	51.26%	24.41%	51.26%
Waipa Networks	0.25%	0.59%	0.81%	0.64%	0.33%	1.01%	0.33%
WEL Networks	0.52%	1.13%	1.81%	1.41%	1.13%	2.36%	1.13%
Wellington Electricity	11.83%	4.24%	4.90%	3.21%	0.83%	0.65%	0.83%
Westpower	0.40%	0.09%	0.21%	0.46%	0.05%	0.03%	0.05%
Whareroa Cogeneration	0.10%	0.03%	0.00%	0.00%	0.02%	0.00%	0.02%
Winstone Pulp International	0.17%	0.29%	0.43%	0.36%	0.07%	0.00%	0.07%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Appendix B Reasons for policy positions in the proposed guidelines

Overview of this appendix

B.1 This appendix sets out the policy intent behind the proposed guidelines to inform stakeholders as to our reasons for preparing the proposed guidelines in their current form. It also sets out a number of potential alternative options relating to the details of the proposed guidelines (more high level alternatives are addressed in appendix E) as well as particular consultation questions we encourage stakeholders to address.

B.2 We acknowledge that there are a number of complex design decisions reflected in the proposed guidelines. While this appendix sets out the Authority's current proposal, building on the work we have undertaken to date, we remain open to considering all points of view and encourage submitters to consider all issues fully. Once we receive and consider feedback, we may decide to proceed with an option(s) other than our currently preferred option. We may also choose to combine options (where applicable) or modify them based on stakeholders' feedback. These final decisions on the design of guidelines will be made in light of the feedback received in response to this issues paper.

Overview of the proposal

Main components of the proposal

B.3 There are four main components in the proposed guidelines:

(a) A connection charge. The guidelines in relation to the connection charge are largely the same as under the current guidelines.

(b) A benefit-based charge.[110] This would seek to charge transmission customers for investments in the interconnected grid in proportion to the net private benefit they get from each investment.

(c) A residual charge. This would allow Transpower to recover anything remaining of its maximum allowable revenue.

(d) A prudent discount policy. This would allow for a reduction in a transmission customer's charges in circumstances where that is efficient.

B.4 In addition to the above four components, we are proposing a price cap to limit increases in transmission charges resulting from the proposal.

B.5 The Authority's view is that the connection and benefit-based charges, along with nodal pricing in the spot electricity market, will provide price signals for efficient grid use and efficient investment decisions and thus operate for the long-term benefit of consumers by reducing costs. The residual charge is designed to collect the remainder of Transpower's recoverable revenue with minimum impact on grid use and investment decisions.

Additional components

B.6 Under the proposed guidelines, Transpower would be required to consider whether to include any of the following 'additional components' in its proposed TPM:

---

110 This is similar to the area-of-benefit (AoB) charge discussed in the second issues paper. When we discuss the benefit-based charge in reference to past TPM publications, we mean the AoB charge. The former name (AoB) does not now accurately describe the nature of the charge (which does not actually require an area to be defined).

(a) a method for determining how charges are recovered for transmission assets that are commissioned in stages

(b) a method for charging for connection assets that are modified so they would otherwise become investments in the interconnected grid if they continue to principally provide connection services

(c) a method for determining the amount to be recovered for new connection assets that is aligned to the method used for the benefit-based charge

(d) a transitional peak charge[111]

(e) a method for expanding the coverage of the benefit-based charge to include further benefit-based investments commissioned prior to the date of the publication of the 2019 issues paper ('pre-2019 investments'),[112] beyond the initial set of recent high–value investments listed in clause 13(b) of the proposed guidelines[113]

(f) a method for allocating operational and maintenance costs on an actual cost basis (as opposed to the use of allocation rules)

(g) a kvar charge on reactive load.

B.7 The proposed guidelines require Transpower to propose each additional component if, in its reasonable opinion, doing so would better meet our statutory objective than not including that additional component.

111 The draft guidelines in the supplementary consultation paper to the second issues paper made provision for what was called a LRMC charge. This has been dropped and replaced by the transitional peak charge. See the further discussion below at B.306 onwards.

112 The proposed guidelines now include an 'Interpretation' section, as proposed for example by Transpower in its submission on the second issues paper. Terms defined in the interpretation section have the same meaning when used in this appendix, unless the context requires otherwise. This includes the definition for a 'post-2019 investment', which is an investment to the extent that it is first commissioned after the publication of this paper (including any part of a pre-2019 benefit-based investment to the extent that it is commissioned after this date). A 'pre-2019 investment' is an investment commissioned on or before the date of publication of this paper.

113 To clarify: by a grid 'investment', we mean the grid infrastructure that results from an overall project, such as the North Island Grid Upgrade (NIGU) Project, which includes a large number of individual grid 'assets', such as transmission towers, conductors and transformers.

Comprehensive discussion of the proposal

Structure and interpretation

Proposal

B.8 The proposed guidelines have been structured so as to assist in their interpretation.

Discussion

B.9 The structure of the proposed guidelines has been improved from that in the 2016 issues paper so as to aid the reader in interpreting the guidelines. These changes take account of proposals by several submitters.[114]

B.10 The structure proposed broadly follows the structure proposed by Transpower in Annex B to its submission on the second issues paper.[115] For example, the proposed guidelines have a separate interpretation section which defines the key terms used in the proposed guidelines and in this chapter.

B.11 The guidelines include a brief initial section on our policy objectives for the guidelines. This sets out the proposed components of the TPM and explains the purpose of each. We would refer to this section if we needed to consider if the TPM has been implemented in a manner inconsistent with the Authority's policy objective under the 'TPM workability amendment' discussed in appendix F (if that Code amendment is made in the future).

General matters

Proposal

Clauses 1 - 8, proposed TPM guidelines (appendix A)

Discussion

B.12 The purpose of this section is to provide Transpower with guidance on how it is to implement the rest of the proposed guidelines, as well as requiring it to include certain general provisions in the TPM.

B.13 This section provides for Transpower, in developing the TPM, to take into account practical considerations and to provide a proposed TPM which differs in its details from the proposed guidelines where doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective. The reason these measures have been included in the general provisions is to provide greater flexibility to Transpower to develop all aspects of the TPM and to simplify the wording of the rest of the proposed guidelines by removing the need to include such provisions throughout.

---

114 For example, the submission by Transpower on the second issues paper and the submission by E Grant Read for Meridian on the supplementary consultation paper. We note that throughout this Appendix there are references to submitters to the Authority's 2016 proposal. While we do not provide a detailed response to all points raised in our consultations relating to the second issues paper, the proposals discussed in this Appendix have developed out of our consideration of the many points raised by submitters (some of which are referenced, where relevant, in this Appendix). If you wish the Authority to consider again an argument or some evidence that you have provided in a previous submission, please feel free to cross refer to the specific place in your previous submission where the point is covered.

115 Clause 2 of Annex B of Transpower's submission.

B.14 Likewise, aspects of the remainder of the proposed guidelines generally allow more discretion than the draft guidelines in the second issues paper. For example, the second issues paper provided a specific fall-back method for allocating the benefit-based charge if the primary method was not practical. Instead, the relevant sections of the proposed guidelines now provide for Transpower to use a proxy for benefits in allocating the benefit-based charge, without specifying what the proxy should be. Similarly, the simple method for allocation of the benefit-based charge is defined separately from the standard method and by reference to the outcome it is intended to achieve.

B.15 The overall effect of these changes is to give Transpower wider discretion in interpreting and applying the proposed guidelines while ensuring any proposed TPM remains consistent with our statutory objective.

B.16 These changes take account of Transpower's submissions that care is needed to ensure the proposed guidelines direct Transpower by laying out clear principles for the TPM but do not unduly foreclose design options and that an overly prescriptive approach risks unintentionally foreclosing development options and adds unnecessary complexity.[116]

B.17 This section also deals with general issues relating to Transpower's reporting in respect of the proposed TPM and for consultation on proposed TPM charges. Transpower would not be required to consult with respect to investments valued lower than $20 million at the time of commissioning.[117] We developed the view (in the course of discussions with Transpower and the Commerce Commission on the workability of the proposal) that this was appropriate in order to reduce administrative burden.

B.18 The Authority considers that it would help customers in their decision making if they are well informed about how their charges are calculated and are able to see how their charges evolve over time. This will in turn increase efficiency, and thus benefit consumers in the long-term, by providing customers with the information necessary to make, or advocate for, the most efficient investment decision. Accordingly, the proposed guidelines include a requirement for Transpower to provide each designated transmission customer with information regarding the basis on which its benefit-based charge and residual charge have been set, including the extent to which the residual charge comprises unallocated opex. They also provide that Transpower is to make it clear exactly how it has calculated a customer's transmission charges, so that the customer could, if it wanted to, take the information and verify the accuracy of Transpower's calculations of its transmission charges.

B.19 The general guidance also provides that in assessing the net private benefit that a transmission customer (for example, a distributor) receives from a transmission investment, Transpower is to include the benefit received by each load or generation party that is indirectly connected through the transmission customer to the grid. That is, any benefit accruing to these parties would be attributed to the distributor. This addresses the issue that those who are actually affected one way or another by the TPM are not necessarily transmission customers. For example, if a transmission investment leads a mass-market consumer to enjoy lower electricity prices, the mass-market consumer is a beneficiary of the investment even though the legal incidence of the benefit-based charge for the investment is borne by the consumer's distributor and even though it is the consumer's retailer which participates in the energy market.

[116] Transpower submission on the second issues paper, page 30, and on the supplementary consultation paper, page 30.

[117] See discussion from paragraph B.121.

B.20 This section of the proposed guidelines also provides that transmission alternatives and transmission investments are to be treated in a consistent manner. This means for example that benefit-based charges would, if practical, be used to recover the costs of any payments by Transpower in respect of transmission alternatives (including distributed generation). This will ensure that transmission customers have appropriate incentives to weigh up transmission and transmission alternatives.

Q10. Do these provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?

Main components

Proposal

Clause 9, proposed TPM guidelines (appendix A)

Discussion

B.21 This clause sets out the main components proposed to be included in the TPM, and also the price cap.

B.22 It also provides that the total recovered by Transpower under these components may not exceed Transpower's forecast maximum allowable revenue (MAR). This is consistent with the TPM's function of allocating the recovery of Transpower's MAR between its customers.

Main component 1: connection charge

Proposal

Clauses 10 and 11, proposed TPM guidelines (appendix A)

Discussion

B.23 We propose that, apart from the matters covered in the additional components, the current guidelines[118] for charging for connection assets would be largely retained.

B.24 The reason is that we consider the current connection charge to be largely consistent with the principles of efficient transmission charging, as discussed in appendix D. This is because it charges parties for the cost of connecting them to the grid. It therefore provides parties with incentives to take connection costs into account in their own investment activity and operations, and to seek the connection option (or an alternative to connection) that most cost-effectively meets their needs.

B.25 These principles are even more important in the context of New Zealand's broader policy goal to reduce carbon emissions. The current connection charge provides parties seeking to electrify load or to build low-emissions generation with the incentive to choose the option

[118] Throughout this paper, references to the 'status quo', 'the current guidelines' or the 'current TPM' should be read as the guidelines and TPM in effect as at the date of publication of this paper.

that achieves lower emissions at lowest cost to the economy as a whole. This should result in lower electricity prices for all electricity consumers over the long run.

B.26 Many submitters on this proposal were broadly of the view that the current connection charge is efficient, and that a change from the status quo would not result in improvements.[119]

B.27 We do propose some related changes in the detail of the guidelines for connection charges to be adopted if, in Transpower's reasonable opinion, they would better achieve the Authority's statutory objective. These are included in Additional Components A to C and F.

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

B.28 We have considered whether any changes are required to connection charges in order to address 'first mover disadvantage'.[120] For example, it may be that it would be efficient in the medium to long term for a new connection investment to be constructed at a scale large enough to accommodate multiple new generators (particularly in a context where renewable generation capacity is growing rapidly). However, the first generator to connect to such an investment may be subject to high charges in the initial period before other generators have connected, and might also bear the risk that the later expected generation connections fail to eventuate. This might inefficiently reduce the number of new generation connections.

B.29 We see three main options:

(a) allow the cost recovery profile for the connection investment to be backloaded (for TPM purposes only)

(b) allow the asset values for the connection investment to be reduced (for TPM purposes only) in the event that the expected connections do not show up

(c) do not attempt to address the issue via changes to the TPM (this is currently our preferred option).

B.30 Option (a) could be used to reduce the connection charges paid by the first generator to connect. The difference in cost would instead be borne by load customers through the residual charge. This would help to address first mover disadvantage. However, it could also lead to inefficient investment decisions. This is because the connecting customer would have less incentive to take into account the costs of transmission in making decisions about its own investment, to the extent it bears a lower proportion of the costs of the grid investment. For example, it could decide to locate in a very remote place requiring an inefficiently large connection investment. This could result in higher costs for the system as a whole (unnecessarily raising electricity prices).

B.31 Option (b) could be used to remove the risk that the later expected generation connections fail to show up from the first generator. The risk would instead be borne by load customers.

---

119 For example:

- in submissions on the 2016 TPM proposal, Meridian, Nova Energy, PowerNet, PWC for 14 EDBs
- in submissions on the TPM connection charges working paper published by the Authority on 13 May 2014 (the 'connection charges working paper') Contact (p.1), Counties Power (p.4), ENA (p.6), Fonterra (p.3), MRP (p.1), Orion (p.1), Pioneer (p.1), Transpower (pp.1, 9), Vector (p.3).

120 See, for example, Fonterra's submission on the second issues paper and Transpower's submission to the Electricity Price Review, October 2018, Part Four: Industry: Generation (response to question 14)

This would help to address the first mover disadvantage. However, it could also lead to inefficient investment decisions. This is because it would require other transmission customers to cross-subsidise the connecting customer, so it would have an inefficiently weak incentive to carefully assess the likelihood that the other connection customers could indeed be expected. This could result in overbuilt connection investments, and higher costs for the system as a whole.

B.32 We are not proposing either option (a) or option (b), because of the potential inefficient outcomes noted in the previous paragraphs. So our current preference is not to make any changes to the TPM in order to address the issue; that is, we prefer option (c).

B.33 There are likely to be other ways to address first mover disadvantage that do not involve changes to the TPM. We would be open to considering other potential avenues outside the scope of the TPM review. In this paper we therefore do not discuss in detail any other options for addressing this issue that fall outside the ambit of the TPM.

B.34 However, we do note that Transpower is able to contract with a customer to make an investment outside the standard regulatory framework (that is, the framework governed by the Commerce Commission's Capex Input Methodology for transmission investment and the TPM). The terms of these new investment contracts can be relatively flexible. For example, such a contract could potentially allow the profile of payments for the investment to be back loaded and / or could allow for a customer's payments to be reduced in the event that the expected connections do not show up. This may allow for a more efficient allocation of costs and of risk, compared to options (b) and (a). This is because it may allow for Transpower and its customer to reach agreement on an efficient allocation of both cost and risk, including the risk of the other parties not materialising, between themselves through a process of commercial negotiation. The cost and risk could be shared between the contracting parties, rather than spread across all load customers. This could help to avoid the risks of inefficient connection investments identified above.

B.35 However, we are conscious that addressing first mover disadvantage and achieving the efficient results discussed in the previous paragraph may require changes to other regulations including some that are outside the Authority's jurisdiction. This may be an issue that requires coordination across more than one agency. We will not consider this issue any further here as it is outside the scope of the TPM review.

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

Main component 2: benefit-based charge

Proposal

Clause 12, proposed TPM guidelines (appendix A)

Discussion

B.36 The proposed guidelines require that the TPM include a benefit-based charge (benefit-based charge).[121]

B.37 The Authority is proposing a benefit-based charge because it would seek to, as far as is reasonably possible:

(a) allocate the cost of each investment in the interconnected grid to those who benefit from it, in proportion to the size of their net private benefit from the investment[122]

(b) fully recover the costs of each investment in the interconnected grid, so such costs need not be recovered through the residual charge (the benefit-based charge would eventually apply across all, not just to a few, grid investments).

B.38 We are proposing that the full cost of each new investment in the interconnected grid be recovered from users of that investment because, as is summarised later in this appendix and is discussed in more detail in appendix D, it provides users of the interconnected grid with better incentives to take into account the cost of providing them with access to the grid

121 Many although not all submissions on the second issues paper supported the introduction of a benefit-based charge, although often with some reservations or qualifications. One reason for this support is that the charge is designed to be service-based and cost-reflective. See, for example, E-Type Engineering, Enernoc, Gore District Council, Grey Power Southland, Invercargill District Council, Market South, McIntyre Dick and Partners, Meridian, Northpower, Nova Energy,, Oji Fibre Solutions, Otago Chamber of Commerce, Otago Southland Employers' Association, Preston Russell Law, Sarah Dowie, South Port New Zealand, Southland Chamber of Commerce, Southland District Council, Southland Manufacturers Trust, Stabicraft Marine, Venture Southland, Winstone Pulp. Others:

- did not favour a benefit-based charge in principle. (For example, Axiom for Transpower considered that the AoB methodology would not have the property of an efficient pricing methodology, which is to elicit desirable behavioural changes before investments are made, and stop undesirable behavioural change after investments are made);
- thought there were practical difficulties with it (for example, Alpine Energy, Unison, Waitaki Power Trust).

We disagree with those who did not favour a benefit-based charge for the reasons discussed in Appendix D and this appendix. We have also endeavoured to design the proposal to take account of the potential practical difficulties (for example, by allowing a proxy for the estimation of benefits).

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

The reason that the Authority prioritises the approaches (in the order of market-based, exacerbators' pay, and beneficiaries pay) is that those ranked higher in this hierarchy are more market-like, in the sense that they:

- devolve to market participants the authority and responsibility for making (and modifying) the investment and charging decisions, as opposed to these being administratively determined.
- sheet home the costs of those decisions to those who make or benefit from those decisions

Those ranked higher are therefore more likely to promote ongoing dynamic and static efficiency gains.

when making their own decisions about their own investment, about using the grid and about whether to support grid investments.[123]

B.39 The Authority considers this reform to be consistent with New Zealand's broader policy goal to reduce carbon emissions. Benefit-based charging would encourage parties seeking to electrify load or to build low-emissions generation to take into account the costs of any upgrade to the interconnected grid that may be required due to their decision. This encourages them to choose the option that achieves lower emissions at lowest cost to the economy as a whole. By avoiding unnecessary cost, this results in lower prices for electricity consumers over the long run. By contrast, incurring unnecessary cost raises the price of electricity, which could discourage consumers and businesses from switching from fossil fuels to electricity.[124]

B.40 The next four sections describe how a customer's annual benefit-based charge for an investment would be calculated.

(a) The next section describes the investments that would be subject to the charge

(b) The section *Benefit-based charge must recover the covered cost of benefit based investments* describes how the total amount (net present value) of the charges for each investment would be calculated

(c) The section *Recovery of the covered cost of a benefit-based investment over time* describes how that total amount would be recovered year by year from transmission customers collectively; that is, it describes how to calculate the annual benefit-based charge for the investment

(d) The section *Allocating annual benefit-based charges among customers* describes how this total annual charge for the investment would be allocated between individual transmission customers.

B.41 Subsequent sections deal with more detailed adjustments and implementation issues.

123 A number of submitters on the supplementary consultation paper agreed that the AoB charge (now the benefit-based charge) is cost-reflective and service-based. For example, Awarua Synergy, Dongwha, EIS, E-Type Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland, Otago Southland Employers' Association, Port Otago, Queenstown Lakes District Council, Dunedin City Council, Clutha District Council, University of Otago.

However, other submitters on the supplementary consultation paper disagreed. Trustpower and Houston Kemp for Trustpower suggested that the AoB charge is neither service-based nor cost-reflective. They consider it is not service-based because it is not applied to a service that can be isolated from other services provided by the network as a whole, and it is not cost-reflective because it reflects benefits. Transpower suggested that the AoB charge will not provide a price signal. Other submitters did not agree that the AoB charge would send desirable price signals. For example, Employers and Manufacturers Association (Northern), MediaWorks.

We disagree with the second group of submitters for the reasons outlined in this appendix and in more detail in appendix D. For example, we consider that a benefit-based charge for use of the grid is analogous in concept, though not in detail, to the example of charging for a hotel bed-night given in appendix D. Our view is that the benefit of providing such a price signal is clear and is demonstrated by the example that Littlechild gives of the grid investment process in Argentina – see footnote 173.

124 See Productivity Commission, *Low-emissions economy - Final report*, August 2018, p.400 (Finding 13.3). Available at https://www.productivity.govt.nz/inquiry-content/3254?stage=4

Benefit-based charge must apply to benefit-based investments

Proposal

Clause 13, proposed TPM guidelines (appendix A)

Discussion

B.42 In our view, allocating the costs of *future* grid investments on the basis of benefits would promote more efficient decision-making, thus reducing costs and generating long-term benefits for consumers. As is discussed further in appendix D, transmission customers that are required to pay a benefit-based charge for a future grid investment will have an incentive to take transmission costs into account in making decisions about their own investments and use of the grid. They will also have a stronger incentive to engage with the Commerce Commission's decision-making process about proposed grid investments. The efficiency of a benefit-based approach to cost allocation is recognised in the economic literature.[125]

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

Should the benefit-based charge apply to past investments?

B.43 However, with respect to past investments we have to make an important design choice. We need to decide whether or not to apply the benefit-based charge to pre-2019 grid investments. This is a difficult decision as the various options have their pros and cons.

B.44 Reflecting this, the views of submitters this subject were also quite mixed. Many submitters on the second issues paper thought historical investments should be included.[126] Of these there was a split between those who thought the benefit-based charge should apply to all pre-2019 investments and those who thought it should apply to a more limited set of investments. Reasons given were varied, but included efficiency concerns, durability

125 An approach to allocating the cost of transmission investments on the basis of benefit is proposed by W Hogan (2011). All academic references are cited in full in the Bibliography.

Professor Hogan is a leading global authority on electricity markets and transmission pricing. He says

> The attraction of the principle that the beneficiaries pay for transmission investment has dimensions of both fairness and efficiency. The fairness criterion is important especially because the cost allocation principles apply to mandated transmission investments that exploit the power of government to compel participation. The emphasis here, however, is on the effect of cost allocation principles on the efficiency of electricity system framework."

Rivier et al (2013), pg 272 ff makes a similar point. The authors state that:

> Short-term signals given by locational energy pricing such as nodal or zonal prices provide incentives for optimal and efficient system operation and for allocating limited interconnection capacity. Their expected value also provides a useful signal for future investors. Long-term signals, given by locational transmission charges, are needed to share the allowed revenues from regulated transmission installations among grid users, while encouraging new supply and demand-side actors to locate efficiently.

The authors also state (pg 293-294) that "The allocation of the cost of a transmission network among its users must obey some basic principles that result from the combination of microeconomic theory, power systems engineering and sound regulatory practice". Specifically "…[four high level] solid principles' have been established" for the allocation of the cost of a transmission network among its users", the first of which is to "allocate costs in proportion to benefits".

126 Eg, Submission on the second issues paper by Contact Energy , Gore District Council, Invercargill District Council, Oji Fibre Solutions , Nova Energy, Pacific Aluminium, Southland District Council, Unison, Venture Southland.

concerns, the desirability of avoiding 'grandfathering' of charges and the desirability of prices that reflect costs.

B.45 On the other hand, there were many submitters on the second issues paper[127] and supplementary consultation paper[128] who thought the benefit-based charge should be applied only to post-2019 investments. Again reasons given were varied, but included avoiding creating uncertainty, efficiency, durability and the desirability of avoiding wealth transfers.

B.46 The three options that we are considering are as follows.

B.47 The first option would be to apply the benefit-based charge only to future grid investments and recover the costs of past investment through the residual charge. This option (which has been assessed in the CBA[129]) has relatively low implementation costs and would avoid the potential difficulties that might arise in implementing a benefit-based allocation for the costs of existing grid assets. It would still promote more efficient decision-making about new investment in the grid (for example, by encouraging transmission customers to take into account the impact of their decisions on the need for new grid investments). The revenue recovered from load customers via the residual charge would be high initially, but would reduce over time as the value of historical grid investments in Transpower's asset base reduced with depreciation.

B.48 The second option would be to apply the benefit-based charge only to future grid investments and recover other costs from the parties that currently pay transmission charges, in proportion to their current payments. This could be arranged via an alternative specification of the residual charge (payable by all transmission customers) that was allocated in fixed proportions (determined by fixing the current allocation of RCPD and HVDC charges). This is similar to the first option; however it would not involve any initial reallocation of charges. Distortions to grid use would be avoided, as charges would be fixed (as opposed to varying according to grid use as with the RCPD and HVDC charges). Revenue recovered from load and generation customers via this alternative residual charge would reduce over time with depreciation.

B.49 The third option (currently our preferred option) is to include some pre-2019 investments in the list of benefit-based investments.

B.50 If we adopt the third option, we would be diverging from overseas precedent. None of the three independent system operators (ISOs) or regional transmission operators (RTOs) we met in the United States applies a benefit-based approach to recover the costs of existing assets.[130] Instead, the costs of such investments tend to be spread more widely.

---

127 Eg, Air Liquide, Auckland Airport, Counties Power, Electricity Ashburton, KiwiRail, Mighty River Power, PWC for 14 EDBs, TECT, Top Energy, Trustpower.

128 Eg, Houston Kemp for Trustpower, Covec, Counties Power, Counties Power Consumer Trust, Northern Federated Farmers, Trustpower, Auckland Airport, Axiom for Trustpower, Trustpower, CEC for Trustpower, Bushnell/Wolak for Trustpower, Professor Yarrow for Trustpower, Vector, Entrust, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower

129 See Chapter 4

130 See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018.

B.51 Further, when we spoke to Professor Hogan during our visit to the United States, he did not approve of applying beneficiaries-pay to historic investments. Rather, his general view was that it is best to allocate the costs of existing assets in a way that does the least harm and avoids as much distortion as possible.[131] That said, Professor Hogan also acknowledged that where an existing cost allocation for historic investments is grossly unfair or is distorting future investment decisions then a revision may be appropriate. However, in making such revisions, great care had to be taken to avoid causing more harm.

B.52 We engaged further with Professor Hogan on this issue after our visit to the United States. We provided him with a discussion paper setting out the pros and cons of recovering the costs of historical transmission investments through a benefit-based charge.[132] In a subsequent discussion with the Authority Board in May 2018,[133] Professor Hogan said that there was nothing that he was aware of that was inefficient or inappropriate in applying beneficiaries-pay to existing assets, provided no incentives for inefficient entry or exit are created. He also noted that such incentives can be avoided by using the tools we have considered (such as the provisions for reassignment in the case of under-utilised assets). (We also note that the potential for inefficient exit is limited by the price cap. We are unaware of any reasons why the proposal would lead to a risk of inefficient entry.)

B.53 We tested the first option as well as the third option in the CBA, and found the quantified net benefits of $2.729 billion for the first option and $2.711 billion for the third option (the Authority's main proposal). Both these estimates fall within a similarly broad range of around $0.2 billion and $6.4 billion. As explained earlier in this paper, the difference between the two options is not material within the context of the net benefits (a difference of less than 1%). Further, the assessment does not take into account unquantified factors.

B.54 Our current view, based on qualitative analysis, is that the third option is the best approach. In particular, we think recovering the costs of some past investments via the benefit-based charge would significantly improve the efficiency of the TPM, for the reasons set out in appendix D (paragraphs D.66 to D.72 below) and for the following related reasons:

(a) It would ensure that customers who do not benefit from these investments would not have to continue paying (through the residual charge) for these pre-2019 investments, whilst also paying (through the benefit-based charge) for their share of the cost of future investments from which they do benefit.[134] Christchurch consumers, for example, could expect to pay the lion's share of the cost of the planned Upper South Island voltage stability project,[135] in addition to paying 9% of the costs of historical projects that benefit mainly North Island consumers.[136] If the charge were applied only to post-2019 investments, it could undermine the viability of some parties

---

131 See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018.

132 Electricity Authority, *Should beneficiaries pay for existing grid assets? Pros and cons of applying an area-of-benefit charge to recover the costs of historical transmission investments*, 8 May 2018

133 See Filenote: *Teleconference with Professor William (Bill) Hogan of Harvard University*, 17 May 2018

134 Several submitters to the TPM options working paper (16 June 15) made this point, including for example Orion (p.9) and Alliance Group (p.2). The TPM options working paper is available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c15374.

135 The planned Upper South Island voltage stability project involves a switching station at Rangitata and a new line to Islington. It is expected to be delivered over 2022 – 2035 at a cost of $283m. Transpower, *Securing our Energy Future 2020 – 2025, Regulatory Control Period 3 Proposal*, November 2018, p.40, Table 10

136 Under the current TPM Orion is expected to pay around $7 million each year towards the costs of just three of the big North Island investments (the North Island Grid Upgrade, UNI reactive support and the Wairakei Ring).

who might be viable if the charges better reflected their share of the costs and benefits of providing them with access to the interconnected grid. It would also result in perceptions of unfairness, undermining the durability (and therefore efficiency) of the regime. This lack of durability could put the overall benefits of the proposal at risk. It would also perpetuate policy uncertainty for investors, and thereby increase the cost of investing, and lead to further resource costs due to ongoing lobbying.

(b) It would address the concerns of some stakeholders with the current TPM that their charges do not reflect the underlying cost of providing them with transmission services and the benefits they receive.

(c) It would discourage rent-seeking behaviour in the future, as it would signal to the market that we are not willing to grandparent historical inefficient regulations. This would reduce any incentive participants have to seek out inefficient regulatory loopholes, as they would anticipate that we would close them when we became aware of them. This would promote dynamic efficiency.

(d) It would improve efficiency by providing information about the value of future investments (as Professor Littlechild noted in his 2016 report).[137]

B.55 Contrary to the views of some commentators[138], changing the charges on pre-2019 investments would not be retrospective. This approach is no different in principle from the government changing the tax rate on existing investments, which is the normal way tax changes are made. The charge would only be retrospective if the *past* charges for the pre-2019 investment were changed. This is not proposed.

To which past investments should the benefit-based charge apply?

B.56 If past investments are to be included, the next decision to be made is to which pre-2019 investments the benefit-based charge will apply. We see several options, as follows. The options are that the benefit-based charge applies to:

(a) all pre-2019 investments except the HVDC assets (and the HVDC charge is retained)

(b) the HVDC assets only (other pre-2019 investments recovered via residual charge)

(c) all pre-2019 investments

(d) a subset of pre-2019 investments including the HVDC (currently our preferred option).

B.57 An important aspect of this issue concerns the treatment of the HVDC assets. Submitters on the second issues paper had mixed views[139] on whether the HVDC assets should be covered by the benefit-based charge.

B.58 One option would be to retain the HVDC charge (and so continue to recover HVDC costs only from South Island generators). An argument for this option would be that South Island

137 Littlechild, S, *Report on the Electricity Authority's Transmission Pricing Methodology Review,* 26 July 2016, page 14.

138 For example, a submission by PWC for 14 EDBs on the second issues paper. Similarly, we do not agree with the submissions of NZ Steel and Orion that the basis proposed for the residual charge in the second issues paper was retrospective.

139 Several submitters on the supplementary consultation paper (eg, Counties Power, Counties Power Consumer Trust, Unison, Centralines, Trustpower, Yarrow for Trustpower, Houston Kemp for Trustpower) and on the second issues paper (NZIER for MEUG, PowerCo) suggested there is a case for retaining the HVDC charge, for example because it enhances transparency and avoids large wealth transfers for limited and uncertain efficiency gains. On the other hand, NERA for Meridian submitting on the second issues paper thought HVDC assets should be included so as to place generators on a competitively neutral footing.

generators are the key beneficiaries of the HVDC link as it enables them to provide electricity to consumers in the North Island (so arguably the current HVDC charge is already a crude benefit-based charge and so no further change to it is required).

B.59 However, in our view the benefits of the HVDC link need to be re-assessed. The beneficiaries of the HVDC link are now broader than the beneficiaries that were contemplated when it was originally decided that HVDC costs should be recovered only from South Island generators. The change in beneficiaries has come about as the result of operational changes. Changes made since the HVDC was originally commissioned include the commissioning of Pole 3 and the decommissioning of Pole 1, and the establishment of a national reserves market and frequency keeping arrangements. The HVDC link now provides more widely spread benefits such as through its role in the provision of ancillary services.

B.60 Further, in 1996 there was no prospect of additional South Island generation being built. Gas-fired power stations were expected to be the most cost-effective way to deal with anticipated growth in the upper North Island. In recent years this situation has changed, and renewable resources – including South Island generation – are now expected to play a greater role relative to gas generation (as illustrated in the Productivity Commission's Low-emissions economy paper of August 2018[140]). The HVDC link will therefore have widespread benefits, to North Islanders as well as South Islanders, for example by allowing anticipated demand growth to be met efficiently by generation located in both islands.

B.61 Our current view is that these changes mean that it is appropriate to revise the allocation of charges and justify HVDC costs being recovered through the benefit-based charge.

B.62 We are proposing that all HVDC assets be covered by the benefit-based charge, including those that were commissioned before May 2004.[141] These pre-2004 HVDC assets have been included because, unlike other pre-2004 investments, they are relatively easy to identify and because including them will:

(a) ensure that those who benefit from the HVDC link pay for it

(b) ensure that all assets that form part of the HVDC link are charged for it on a consistent basis

(c) promote durability.

B.63 The next question is whether to recover the costs of only the HVDC assets through the benefit-based charge, or whether to extend it to other pre-2019 investments.

B.64 We do not consider it would be appropriate to limit the benefit-based charge to recovering the costs of only the HVDC assets. In our view, recovering the costs of a wider subset of pre-2019 grid investments via the benefit-based charge would better promote the efficiency of the TPM, for the reasons set out at paragraph B.54. These reasons apply as much to transmission assets in the interconnection category as to those in the HVDC category.

B.65 However, we are not proposing to extend the benefit-based charge to *all* pre-2019 grid investments. We currently prefer to apply the charge to a subset largely restricted to recent, major investments. The seven investments in clause 13(b) of the proposed guidelines:

(a) were approved after May 2004 (other than HVDC Pole 2, which is older)

140 Available at https://www.productivity.govt.nz/inquiry-content/3254?stage=4

141 In its submission on the second issues paper, Contact Energy proposed that all HVDC assets should be included in the AoB charge

(b) had an approved value over $50 million at the time the investment was approved

(c) have estimated benefits exceeding their cost.

B.66 We are proposing to restrict the charge's coverage based on date and cost because the benefits of applying the benefit-based charge to pre-2019 investments need to be traded off against the additional costs of applying the benefit-based charge to those investments. The $50 million threshold limits the application of the charge to a relatively small number of investments, which should reduce implementation costs. However, it still captures a large part of the total value of pre-2019 investments that have been approved since May 2004, effectively addressing the issues discussed in paragraph B.54 above. Also, there is relatively good information available for investments approved since May 2004.

B.67 We are proposing to restrict the charge's coverage to those investments that have estimated benefits exceeding their cost for the following reasons. For a pre-2019 benefit-based investment, unlike for an efficient new investment, it is possible that the benefits that transmission customers collectively are now expected to get from that investment might be less than the covered cost. This could occur, for example, because the benefits that the investment is now expected to provide are quite different from the benefits that were expected when the investment was made. We are of the view that it would be inappropriate to set initial benefit-based charges for these investments that exceed the benefits they are now expected to yield. We have put this into practice by choosing initially to apply the benefit-based charge only to pre-2019 investments where we estimate that the benefits exceed the covered cost.[142]

B.68 We are open to the view that it may be preferable for more (potentially all) pre-2019 investments to be subject to the benefit-based charge. We have therefore allowed Transpower (via Additional Component E) to subject more pre-2019 investments to the benefit-based charge if to do so would promote our statutory objective.

Q14. Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

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

[142] We have also put this into practice by explicitly including a cap on the initial benefit-based charges for any other pre-2019 investment that is included by the application of Additional Component E.

Benefit-based charge must recover the covered cost of benefit-based investments

Proposal

Clause 14, proposed TPM guidelines (appendix A)

Discussion

B.69 For the reasons described above and in appendix D, we are proposing that transmission customers who benefit from a transmission investment would collectively pay a benefit-based charge equal to the covered cost of the investment (as defined below), unless a variation is specifically allowed by the guidelines. This section of the proposal describes how to calculate the covered cost of the investment.

B.70 The costs to be included in the covered cost depend on when the investment is commissioned. For a post-2019 investment, the covered cost is the net present value of the total cost calculated over the entire life of the investment. For a pre-2019 investment, the covered cost is the net present value of the depreciated capital cost in Transpower's regulatory asset base at the time the benefit-based charge is first applied to the investment, the cost of capital on that amount, and all the other costs attributed to the investment from the time the benefit-based charge is first applied to it.[143]

[143] This is consistent with some submissions on the second issues paper that depreciated assets should not be charged for in a way that allows Transpower to recover more than they are worth / recover their costs more than once. For example, Venture Southland, Awarua Synergy, Dongwha, EIS, E-Type Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland.

This treatment is different from what would happen in workably competitive markets. As discussed in appendix D, in workably competitive markets, assets would continue to be charged for so long as they continued to provide services. Further, because transmission is a utility-type services, the charges in each year would not depend on the age of the investment providing the service. These charges would continue so long as the investment continued to provide those services, irrespective of its initially expected life. Competition in the product market would then set the level of prices for transmission services to just recover the cost of the assets, including a normal return on capital. If transmission charges were set in this way, they would come to resemble a tilted postage stamp over time (with the critical difference that beneficiaries of new transmission investments would face, and so have the incentive to take into account, the cost of new transmission investments in their decision making).

The different treatment proposed here is necessary in part because, for good reason, the Commerce Commission regulatory regime requires that Transpower recovers no more than the full cost of each new investment. Our view is that, given this, any method of transmission pricing will be imperfect, in the sense of leaving in place some adverse incentive that would be eliminated in an ideal world.

As is discussed in more detail in this section and in appendix D, the treatment we propose here (where the charges recover just the covered cost of the investment from those who benefit from it) ensures that transmission users have an incentive to take account of the cost of the impact on new transmission investment of their own investment and use decisions, and to seek replacement investment only when the benefit to New Zealand of that replacement investment exceeds its cost. However, it means that charges differ from what we would expect to see in workably competitive markets. In particular, it is one reason that Transpower's customers will pay different charges for the same level of service based on the age of the transmission asset supplying them (as Northpower noted in its submission on the supplementary consultation paper) which could lead to inefficient incentives on load and generation when they are making locational decisions. This potential inefficiency is taken into account in the CBA discussed in chapter 4. (Another reason that charges vary with the age of the investment is the way the costs of an investment are recovered over time, as is discussed below).

We consider that it is impossible to eliminate this locational distortion except by spreading the costs of both new and existing investments widely (for example, through tilted postage stamp pricing). However, spreading costs widely would forgo the advantages of applying the benefit-based charge to new investments discussed in this appendix and appendix D.

B.71 The covered cost of the investment therefore includes any cost attributable to the investment. Thus, for example, it would include the cost of site preparation and decommissioning of the investment if that is necessarily incurred as part of undertaking the investment. Allocating expenses to the asset to which they are attributable would better promote efficient grid use and investment (and therefore a reduction in costs, producing long-term benefits for consumers). That is because these costs would then be recovered through the benefit-based charge relating to the investment in question, so the transmission customers that benefit from the investment would face its full cost and take that into account in their decision-making.

B.72 Opex for connection investments is currently spread across connection customers using broad cost allocation rules. In a similar manner, the proposed guidelines will allow Transpower to use broad cost allocation rules to allocate opex to benefit-based investments. Additional component E requires Transpower to consider attributing operating and maintenance expenditure to the investment they are spent on without using a proxy or generalised allocation rule if that would better achieve our statutory objective.

B.73 Transpower's unallocated expenses (mainly overheads) for owning and operating the transmission grid amounted to $198 million in the financial year 2015/16. If any of these overheads are attributable to a benefit-based investment, they would, under this proposal, be included in the covered cost of the investment.[144] In that case, this would reduce the level of unallocated expenses so that it represents, as much as practicable, only true 'common costs'.[145] These would be recovered through the residual charge, as discussed below.

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

144 Some submissions on the second issues paper proposed this; eg, MEUG, NZIER for MEUG, Southport NZ.

145 Common costs are costs that are incurred irrespective of the addition of a customer or service.

Recovery of the covered cost of a benefit-based investment over time

Proposal

Clauses 15 - 17, proposed TPM guidelines (appendix A)

Discussion

B.74 This section of the proposal addresses how the total benefit-based charge for an investment would be converted to annual charges (the 'annual benefit-based charges'). This determines when in an investment's life the charges are paid. The annual benefit-based charges for an investment are set so the net present value of those charges is equal to the benefit-based charge for the investment.

B.75 We need to make a number of decisions in this area. We need to decide whether to use the method used by the Commerce Commission or another methodology we call indexed historical cost ('IHC'). And we need to decide which of these methods to apply to future (post-2019) investments, and which to apply to past (pre-2019) investments. There are a number of options, including applying:

(a) the Commerce Commission method for both future and past investments

(b) IHC for both future and past investments

(c) IHC for future investments and the Commerce Commission method for past investments (this is currently our preferred option).

B.76 Submissions were quite mixed on which method is most appropriate and in their reasons for favouring particular approaches.

B.77 Some favoured DHC or opposed IHC because:

(a) DHC would result in market-like outcomes, since workably competitive markets with characteristics like transmission investment are characterised by long-term contracts whose typical features include charges that are higher in the earlier years of the asset's life than in later years and that reflect conditions at the time that the contract was made[146]

(b) IHC would not reflect the realities of a workably competitive market and would be contrary to the approach of the Commerce Commission. This could result in misalignment and divergence from the revenue requirement, and may not pass the test of consistency with clause 12.89 of the Code[147]

(c) the probability of technological change supports charging for a greater proportion of the costs of assets in the near future, when the nature of demand for transmission and distribution services is clearer[148]

(d) for pre-2019 investments, IHC could result in charges for some investments exceeding the cost of the investment, which might be subject to legal challenge[149]

---

146 For example, Yarrow for Trustpower submission on supplementary consultation paper, Pacific Aluminium cross-submission on supplementary consultation paper.

147 For example, submission on the supplementary consultation paper by NERA for Meridian Energy, Littlechild for Meridian, Pacific Aluminium, New Zealand Aluminium Smelter.

148 For example, Littlechild for Meridian submission on the supplementary consultation paper, Meridian cross-submission on supplementary consultation paper.

149 For example, submissions on the supplementary consultation paper by: Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, Venture Southland, Awarua Synergy, Dongwha, EIS, E-Type

(e) developing IHC would be unnecessarily complex[150]

(f) arguments for IHC are based on a false scientism and are not informed by pragmatism[151]

(g) if IHC is adopted, the balance between IHC and DHC on each investment will need to be recovered through the residual charge. This impact on the residual charge needs to be taken into account in determining whether IHC or DHC is preferable. Furthermore, the result may not be durable.[152]

B.78 Some favoured IHC or opposed DHC because:

(a) an IHC method is more market-like than DHC[153]

(b) an IHC method for valuing existing assets is consistent with service-based pricing, and in a competitive market, suppliers would charge for services and not individual assets[154]

(c) DHC will not deliver outcomes that are market-like/consistent with competitive markets. This is because charges will be based on the age of an asset, rather than the level of service the asset provides[155]

(d) DHC would result in transmission charges falling as transmission becomes constrained, and as aggregate private benefits and LRMC increase, which would not provide dynamically efficient price signals, and would not be consistent with the beneficiaries-pay principle[156]

(e) using DHC for pre-2019 investments would create an inconsistency between benefit-based investments and connection investments[157]

(f) arguments for using DHC are flawed, as prices in other markets (eg, mobile telephone services) do not depend on the age of the asset providing the service.[158]

B.79 Some proposed that the same method should be used for pre-2019 and post-2019 investments on the basis that calculating the AoB charge (now the benefit-based charge) should be as time-neutral as possible.[159]

Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland, Contact Energy, E. Grant Read for Meridian, Meridian, NERA for Meridian, Littlechild for Meridian, Pacific Aluminium. In accordance with these submissions, the proposed guidelines provide that the benefit-based charge should recover the covered cost of the investment, which takes account of the depreciation that has already been recovered on pre-2019 investments.

150 For example, submission on the supplementary consultation paper by Axiom for Transpower, Pacific Aluminium,

151 Meridian, cross-submission on supplementary consultation paper.

152 Pacific Aluminium, submission on the second issues paper and cross-submission on supplementary consultation paper.

153 Counties Power and Vector, cross submission on supplementary consultation paper.

154 Houston Kemp for Trustpower, cross-submission on supplementary consultation paper.

155 For example, Vector, Counties Power, cross-submission on supplementary consultation paper.

156 Transpower, cross-submission on supplementary consultation paper.

157 Vector, cross-submission on supplementary consultation paper.

158 For example, Counties Power and Vector, cross-submission on supplementary consultation paper.

159 For example, submission on the supplementary consultation paper by Transpower and cross-submisison on the supplementary consultation paper by PWC for 14 EDBs and Vector.

IHC for future investments

B.80 For each post-2019 investment, we propose that Transpower determine the recovery profile over time for the purposes of the benefit-based charge using a methodology we call indexed historical cost ('IHC').

B.81 Under the IHC approach, Transpower would set the annual benefit-based charges for post-2019 investments by dividing the expected[160] benefit-based charge into equal annual amounts over the benefit-based investment's expected life. This would then be adjusted for inflation. In other words, the annual benefit-based charge for the investment would change over time in line with a price index, unless Transpower makes one of the other adjustments discussed below.

B.82 Transpower would decide on the price index it will use in implementing IHC. This allows Transpower to choose the most appropriate index (for example, one that accounts for technological change).

B.83 The IHC approach we have proposed for future investments is consistent with the way that we think charges would be set in a workably competitive market for utility-type services. As discussed in appendix D, such a market is a useful benchmark, because workably competitive markets are relatively efficient.

B.84 We are of the view that the most reasonable assumption[161] to make is that the services provided by a transmission investment will be roughly constant over its life. This is because for utility-type services, the services an investment is capable of delivering do not degrade as the asset providing the service ages and therefore charges do not reflect the age of the asset providing the service. For example, the hire charges for renting a trailer typically do not depend on the age of the trailer.

B.85 As a result, IHC-based charges (which are roughly constant after adjusting for inflation) better reflect the value of the services provided by a transmission investment across its life, than charges based on depreciated historical cost (DHC), which decline over the asset's life.

B.86 However, the proposed guidelines allow Transpower to propose a different method than IHC in the TPM if it considers that this would better meet the Authority's statutory objective than the IHC method and would still recover the covered cost of the benefit-based investment.

B.87 We have considered whether the proposed guidelines should allow Transpower to recover the covered cost of any particular high-value[162] post-2019 investments in a different way from IHC, if applying IHC would lead to charges that manifestly do not reflect the benefits the investment provides. However, our current thinking is that IHC should be used for all post-2019 investments (unless Transpower identifies a method which better meets our

160 'Expected' because the charge is set before the actual covered cost (which is what is eventually recovered) is known with certainty.

161 Of course, the services provided by the investment in actuality will not be constant, but may increase or decrease over time depending on the pattern of growth in the grid, in load and in generation. We think assuming IHC is a reasonable approximation.

162 The definition of high-value benefit-based investments would include all major capex under the Commerce Commission's Capex IM. The threshold proposed in the second issues paper was $5m. Some submitters on the second issues paper, such as Transpower, proposed that the threshold should be aligned, as is now proposed, with the threshold under the capex IM. The threshold for major capex under the Capex IM is $20 million, and the definition of high-value investments includes all investments that have a value exceeding that amount (eg, replacement and refurbishment expenditure as defined in the Capex IM).

statutory objective in which case that method would apply to all post-2019 investments). While this may mean that the charges may not reflect the benefits over time, we think there are countervailing arguments:

(a) the benefit-based charge would still reflect the overall benefit those charged for the investment are expected to get over the benefit-based investment's life

(b) once the investment is made, the salient charge for the customer is the total transmission charges the customer faces, and variations in charges for individual investments would tend to average out in those total charges

(c) introducing such a rule would create another arbitrary boundary with the associated costs that that generates.

IHC for pre-2019 investments

B.88 We have also considered applying the IHC method to past investments.[163] The argument for doing so would be that the services provided by a transmission investment will be roughly constant over its life. However, our view is that there are stronger arguments for applying a different approach to past investments. These reasons are explained in relation to the Commerce Commission method below.

Commerce Commission method for pre-2019 investments

B.89 For pre-2019 benefit-based investments, we propose to determine the capital cost and cost of capital recovered in each year so they are the same as Transpower's annual recovery of those capital components under Transpower's individual price-quality path determined by the Commerce Commission under Part 4 of the Commerce Act ('the Commerce Commission method'). This then determines the recovery profile of the covered cost over time.

B.90 The Commerce Commission's method currently values assets at their depreciated historical cost (DHC).[164] This means that the capital cost of the assets in an investment at the start of the new TPM would be the DHC of the assets as recorded in Transpower's regulatory asset base (RAB). The value of the assets in every year would be the amount specified in Transpower's RAB at the start of that year. This means the benefit-based charge would recover the capital cost of the investment according to the annual depreciation allowance attributable to the investment in the RAB.

B.91 In that case, the benefit-based charge for an investment in any year would be calculated as the sum of:

(a) the depreciation of the investment over the year[165]

(b) the return on capital for the investment over the year

(c) the operating costs, maintenance costs and other costs (if any) attributed to the investment in the year

(d) any other costs attributable to the investment.

---

163 This was proposed by Axiom for Transpower, Castalia for Genesis and Powernet in their submission on the second issues paper. The reasons advanced included that IHC is more service based, and that it would limit price shocks when aging assets are replaced.

164 This is explained in more detail in the second issues paper.

165 If the investment were revalued for some reason, the revaluation would be treated as income (that is, negative depreciation).

B.92 If the Commerce Commission adjusted the Commerce Commission method, the annual charges for pre-2019 benefit-based investment would be adjusted accordingly.

B.93 The Authority considers that the approach is likely to be more efficient than other options, including applying IHC, for five reasons.

(a) It recovers just the total cost of the investment over its life.[166]

(b) It reduces inefficiencies that could result from Transpower possibly needing to scale back its charges (in the event that the rate of grid investment slows in real terms over time), as is discussed below.

(c) It will reduce the inefficiencies that would be caused by a time-varying residual charge if pre-2019 investments were valued using IHC.

(i) If the method used for setting the recovery profile (for either post-2019 or pre-2019 investments) were different from the Commerce Commission method, the residual charge would have to be adjusted over time to allow for the difference between the DHC charges (which are the same as Transpower's recoverable revenue attributable to the investment) and the actual charges. If IHC is used for any investment, the effect of using IHC on the residual charge is positive in the early years of an investment's life and negative in the later years. This is because an IHC-based charge will be lower than a DHC-based charge in the early years but greater in the later years.

(ii) Other things equal, a varying residual charge is less efficient than a constant one that generates the same present value of revenue. This is because the inefficiency generated by a tax-like charge increases more than proportionately with the rate of the charge. Using the Commerce Commission method for pre-2019 investments avoids them causing this inefficiency.

Commerce Commission method for post-2019 investments

B.94 We have considered the option of applying the Commerce Commission method to post-2019 investments as well as pre-2019 investments.[167] This would have the same efficiency benefits as those outlined in paragraph B.93 above.

B.95 However, the Authority considers that for post-2019 investments, on balance, these advantages are outweighed by having annual price signals that better reflect the flow of services delivered by the investment, as discussed above. These efficiencies are likely to be more substantial for future investments, compared to pre-2019 investments, because the prices charged for pre-2019 investments cannot affect whether the investment is undertaken.

166 DHC recovers most of the cost of an investment in the early years of an asset's life, whereas IHC recovers relatively more later in its life. So using DHC for the start of the investment's life and IHC for the end could overall recover more that the total cost of the asset.

167 Submitters who supported using DHC for post-2019 investments had a variety of rationales, as is discussed above. These included that: deviation from the Commerce Commission method had no clear benefits and was complex; that it could cause price shocks when new investments are made; and that consistency with the treatment of pre-2019 investments is desirable. See for example the submissions on the 2016 TPM proposal by ENA, Meridian, NERA for Meridian, Pacific Aluminium, Unison and Vector.

Q17.	**How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method?**

Adjustment to charges and recovery of covered cost

B.96 The proposed guidelines allow Transpower to adjust benefit-based charges where, in its reasonable assessment, there has been or will be a material change in the WACC, opex, the expected life of assets or any other costs attributable to the benefit-based investment, as it is likely that these will turn out differently from Transpower's initial assumptions. However, the requirement to recover the covered cost of the investment would remain, for the reasons discussed above.

Charges would continue until covered cost is fully recovered

B.97 Because the annual benefit-based charges must be set before some of the expenditure to which they relate is undertaken, there is likely to be a difference between the costs anticipated when the charges are set and the costs that are incurred in practice. In part this discrepancy can be dealt with by the adjustments described in paragraph B.96 above. However, it is likely that some discrepancy would remain. This means that Transpower would need to include in the TPM some mechanism for ensuring that the covered cost is recovered. For example, it could provide for a wash-up, or it could continue charging the benefit-based charge until the covered cost has been fully recovered, irrespective of the actual life of the investment. The annual benefit-based charge would reduce to the ongoing costs of the investment (such as opex and de-commissioning costs), after all other costs of the investment had been recovered.

Damage to a benefit-based investment

Proposal

Clause 18, proposed TPM guidelines (appendix A)

Discussion

B.98 As is noted from paragraph B.36 above, we intend that the beneficiaries of an investment will pay the covered cost of the investment over its expected life, because this creates efficient incentives for use of the grid and investment and thus long-term benefits for consumers.

B.99 However, in a workably competitive market, it would be unusual for a user to pay charges on an investment that is no longer delivering services to them. We therefore propose that charges may cease or reduce when an asset in an investment is substantially damaged or destroyed. The proposals under the heading *General matters* above mean that Transpower will have to ensure, as far as is reasonably practicable, that the proposal does not create inefficient incentives on transmission users to take actions that result in such a reduction. For example, it might require that charges would reduce only if the damage was caused by an event that nobody could have predicted or controlled.

B.100 Any costs associated with the investment that are no longer recovered through the benefit-based charge due to the application of this provision will instead be recovered through the residual charge.

Allocating annual benefit-based charges among customers

Proposal

Clauses 19 - 26, proposed TPM guidelines (appendix A)

Discussion

Benefit-based charge allocated according to net private benefit

B.101 Transmission investments can have a broad range of benefits. For example:

(a) (for load) access to more and cheaper sources of electricity

(b) (for generators) access to higher-paying, distant customers

(c) reliability benefits (such as a backup source of electricity for load that is reliant on distributed generation)

(d) local voltage support

(e) nationwide benefits from HVDC link (eg, facilitating cross-island provision of ancillary services and price competition between generation).

B.102 This section of the proposal sets out how the benefit-based charge for an investment is to be allocated in proportion to each customer's share of net private benefits from the investment.[168]

B.103 For example, if Transpower were considering a new investment that would strengthen grid capacity to the upper South Island, the benefit-based charge would apply to all expected beneficiaries[169] of that investment. The beneficiaries might include:

(a) upper South Island load, which benefits from improved reliability and from continuing to have their demand for transmission services met in the face of growth in load

(b) lower South Island generation, which is able to export more electricity to the upper South Island

(c) load and generation across the grid which benefits through reduced losses.

---

168 As is noted in footnote 125, the approach to allocating the cost of transmission investments outlined in this section is consistent with that proposed by Rivier et al (2013), pg 272 ff. and by W Hogan (2011).

Professor Hogan further comments on page 13

> Note that there is nothing in the transmission investment decision or ex ante cost allocation rule that depends directly on examination of the power flows across individual lines or other transmission facilities. The estimate and comparison with the counterfactual is made at the first stage. This ex ante perspective is unavoidable in evaluating the investment decision. Given the complexity of network interactions, where the power flows across individual lines do not describe actual use or value in any economically meaningful way, the only available methodology based on first principles is to allocate costs according to the same estimates of the benefits the future outcomes. This is consistent with the perspective for the beneficiary-pays principle as described by FERC: "Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities" (FERC 2010, p. 91). The cost allocation is made ex ante based on the same analysis that is and must be made before the investment goes forward. The cost allocation does not depend on the ex post utilization that actually occurs, which is difficult to even define much less measure.

169 As provided for under the heading *General matters* above, transmission customers are regarded as agents for parties (both load and generation) indirectly connected through them to the interconnected grid. For example, any benefit that accrues to a distributor's load customer would be attributed to the distributor. Transpower correctly made this point in the comment about clause 13 of appendix B of it submission on the second issues paper.

B.104 Also, the charges each customer faces should reflect its share of the benefits that all beneficiaries would be expected to receive. This would likely mean that upper South Island load and lower South Island generation would pay the most towards the costs of the project, but some of the costs would be borne by other customers expected to benefit.

B.105 As Hogan notes, workable application of the principle could include some spreading of the benefits across different parties at the same location.[170] For example, it may be appropriate to effectively spread the cost of a computer used to bill Transpower's customers across all of its load customers.[171] However, we would expect such situations to be rare for benefit-based investments. For example, the cost of a computer used to manage the HVDC link would be recovered from those who benefit from the HVDC link in the same manner as the link itself.

B.106 We have proposed a benefit-based charge because it allocates the cost of upgrades to the interconnected grid in a way that ensures that those who benefit from the investment pay for it. As is discussed in appendix D, this is relatively efficient because it is consistent with what happens in workably competitive markets. One result is that a user faces incentives which encourage it to take account of the impact on its decisions on the need for grid investments.[172] It therefore provides users of the interconnected grid with incentives to:

(a) take into account the transmission investment implications of their own investment decisions and their decisions about the use of the grid

(b) better scrutinise proposals for new transmission investment.[173]

---

170 See page 11 of W Hogan (2011).

171 Indeed, under our proposal, the cost of such a computer would form part of Transpower's overhead costs and so be recovered through the residual charge (ie, spread across all load customers).

172 Some submitters on our earlier proposed area-of-benefit charge appeared to believe that we intend the benefit-based charge to promote coordination of the use of the grid to efficiently defer investment, and point out that it does not have this effect. In particular, some submissions on the 2016 TPM proposal have suggested that a long run marginal cost (LRMC) charge is also required to do this.

Our view is that locational marginal pricing provides this coordination role by efficiently restricting grid use to capacity. We therefore disagree that there is a need for an additional charge, such as an LRMC charge. This is discussed further in appendix E.

173 Submitters on the second issues paper had mixed views on the potential benefits of increased scrutiny. Some (eg, CEC for Trustpower) thought it might have no effect or might actually decrease engagement in the grid investment process. Others (eg, NERA for Meridian) thought it would improve information disclosure and engagement in the grid investment process.

For the reasons outlined in appendix D, we agree with the latter. This is demonstrated by the example that Littlechild gives of the grid investment process in Argentina. He says

> Soon after the new [benefit-based charge] policy was implemented, a Fourth Line from the gas producing area of Comahue to the capital Buenos Aires was proposed but rejected by a majority of market participants. This line was allegedly much needed, and had been widely canvassed under the previous regime. The rejection was perceived as evidence that the Public Contest method did not and could not work. It seemed that transactions costs outweighed the advantages of cooperation between market participants. …
>
> Subsequent and more detailed research has shown that the Fourth Line was expensive, premature and uneconomic. (Littlechild and Skerk 2008b) Delaying its construction was evidence that the Public Contest method did work, not that it didn't work. In the short term, the participants agreed instead to expand capacity by installing capacitors, at a fraction of the cost of a new line. When conditions later made the Fourth Line attractive, the participants worked together well to design, propose and pay for a line that attracted almost unanimous support and was constructed at a significantly lower cost than envisaged in the initial rejected proposal. Subsequently, it became apparent that it was more economic to transport gas from Comahue to Buenos Aires, and build the power stations there, than to build more long-distance transmission lines.

B.107 The Authority considers that these incentives are likely to be better than those provided by the current HVDC and interconnection charges, or any method likely to be feasible under the current guidelines.

B.108 For example, suppose a potential investor in a gas-fired generator was not charged for a transmission investment needed to carry energy from its generator to the point of load, but was charged for the transport of gas. This would encourage them to site the generator next to the gas field, even if it was lower cost overall to locate next to the point of load.

B.109 The Authority's view is that requiring generation customers to pay the benefit-based charge will not cause inefficient pass-through in the wholesale electricity market. This is because the wholesale electricity market is workably competitive. So generators will face competitive pressure to submit offers which reflect their SRMC of generation. While downstream prices may or may not be higher on average than if transmission could be provided costlessly, any higher price would simply reflect the total resource cost of supplying electricity.[174]

B.110 The proposed requirement that the benefit-based charge be allocated according to the net private benefit that the parties are expected to receive from the investment is different from, but related to, the focus of the Commerce Commission's Investment test. The Investment test considers the total expected net electricity market benefits (instead of parties' net positive private benefits).[175,176] The treatment of benefits for the proposed benefit-based charge is required to be consistent with, though not necessarily identical to, the treatment of benefits for the Commerce Commission's Investment Test.[177] This is intended to enhance consistency with the Commerce Commission's regime and to allow Transpower to implement the benefit-based charge in a more cost-effective manner.

B.111 The proposed guidelines provide Transpower with the discretion to include wider benefits, such as environmental or visual amenity benefits. We are not expecting this discretion to be used much, since such benefits are normally dealt with by other processes and regulations. We have included it to allow for the situation where those processes are inadequate and where limiting benefits to electricity market benefits would prevent Transpower from allocating a significant proportion of the benefits from a transmission investment to those who benefit from it. One example might be the benefits in terms of visual amenities and property values (for example) that might arise if Transpower was required to underground transmission lines.

B.112 Consistent with what happens in workably competitive markets, we consider that charges should be set on the basis of net benefits from the investment, that is, benefits minus

See Littlechild (2011), page 18.

This example also illustrates that, contrary to the suggestion of Axiom for Transpower in its submission on the supplementary consultation paper that customers may not respond to the price signal sent by the benefit-based charge, that at least in some circumstances, customers can and do respond to that price signal.

174 This is discussed further from paragraph D.71 below.

175 , This responds to Transpower's submission on the supplementary consultation paper that the wording proposed there might inappropriately bring in non-electricity market benefits.

176 Major capex involves a specific investment proposal that is considered by the Commerce Commission. The major capex investment test requires Transpower to identify, and the Commerce Commission to assess, expected electricity market benefits and costs that are received or incurred by consumers of transmission services, during the calculation period.

177 In its submission on the second issues paper, NERA for Meridian suggest that this may reduce the costs of implementing the benefit based charge.

costs.[178] This means the benefit-based charge only applies to customers that are expected to receive positive net benefits from the investment.

B.113 Likewise, the charge would not involve compensating parties that suffered dis-benefits from an investment. Compensating parties facing net dis-benefits would:

(a) open the regime up to rent-seeking, as there is no limit to the size of dis-benefits, whereas benefits only need to exceed costs for the charge to apply

(b) increase the rate of the charge, which increases the risk of inefficient behaviour to avoid the charge.

Net load versus gross load for the benefit-based charge

B.114 There is a design choice as to how Transpower should measure demand in order to estimate the benefits of an investment for load customers. There are three main options:

(a) a 'net load' approach: a load customer's demand is measured as off-take at the GXP (we call this approach 'net' as measured demand is lower to the extent that there is injection by distributed generation and/or behind-the-meter generation into a distributor's network or behind a load customer's meter)

(b) a 'gross load' approach: a load customer's demand is 'grossed up' by adding injection by distributed generation and/or behind-the-meter generation

(c) a more flexible approach under which neither of the above approaches is required (this is currently our preferred option).

B.115 The Authority considers the net load approach would be best in most circumstances, as it is likely to provide load customers with appropriate incentives with respect to future investment. This is because a net basis for calculating benefit-based charges better reflects the benefits that customers receive from grid-delivered electricity. That is, a load customer that derives a substantial proportion of its electricity requirements from distributed generation does not benefit from the grid to the same extent as a load customer of similar size that lacks distributed generation. Use of local generation reflects a private judgement that costs of grid supply outweigh benefits. We applied a net load approach in allocating the costs of the seven recent major investments in clause 13(b) of the proposed guidelines.

B.116 However, in some circumstances a gross load approach could be better, as it could avoid a potential efficiency issue. The net load approach has the potential to create an artificial incentive for generation to embed in a load customer's network (and vice versa). This can be seen by considering the following example:

(a) a distribution network that has generation embedded in it

(b) a congestion-relieving investment that benefits the distributor and others is about to be made

(c) the net benefit of the parties is proportional to their net load.

---

178 The draft guidelines published in the second issues paper made explicit that a party's loss of LCE payment as the result of an investment is a dis-benefit. We have not done so in the proposed guidelines, because it simplifies them and because we think that it is clear that a loss of future LCE is a private cost. If Transpower chooses to apply the benefit-based charge to all pre-2019 investments, then including loss of LCE in the calculation of net benefits would have the effect of ensuring that the cost of the new investment is borne primarily by the parties whose growth in demand led to the investment.

B.117 In this example, the distributor's net load is less with embedded generation, compared to the situation where the generation is grid-connected at the distributor's GXP.[179] As a result, its assessed share of benefits is reduced. Potentially, therefore, this creates an incentive for the distributor to encourage generation to embed within its network.

B.118 This situation may not often be problematic. It is an empirical question as to whether or not the potential inefficient incentive is likely to be material. The Authority considers that the potential incentive is unlikely to have material effects on efficiency, because the costs of embedding can be substantial. However, it cannot be entirely ruled out.

B.119 The Authority prefers a more flexible approach under which neither of the above approaches is required. This is consistent with our less prescriptive approach with respect to the method that Transpower may use to determine benefit-based charges. The expectation would be that, for the purposes of calculating benefit-based charges, Transpower will generally measure a load customer's demand as off-take at the GXP (net load approach). However, Transpower can adopt a gross load approach if it considers the potential inefficiency from adopting a net load approach is likely to be material in any given case and mitigating the problem would be consistent with the Authority's statutory objective. Transpower would need to take any potential inefficiency into account in the detailed design of the benefit-based charge.

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

B.120 It is possible for a transmission customer in some scenarios to be an importer of electricity and in other scenarios to be an exporter of electricity.[180] Such a customer may be assessed as benefiting as an importer, an exporter, or both. Transpower will need to separately estimate the share of each customer's charges that are associated with exporting and importing. Further, if this becomes public (e.g. it could possibly do so as part of Transpower's consultation process on the parameters used to calculate TPM charges), then the information would enable distributors to assess the charges arising as a result of distributed generation on their network.

Standard method and simple method

B.121 We propose to differentiate between high-value and low-value post-2019 investments as there are more likely to be net benefits from a more precise allocation of the benefit-based charge for high-value compared to low-value investments.

B.122 There are three broad options for the treatment of low-value investments:

(a) allocate costs via the residual charge

(b) allocate costs via the benefit-based charge using a simple method (currently our preferred method)

(c) allocate costs via the benefit-based charge using the standard method.[181]

---

179 The same applies with respect to any generation that is located on the distributor's side of the constraint that the investment is relieving.

180 A party providing energy storage services using a battery, for example, would be a load customer when charging its battery and a generation customer when discharging its battery.

181 This was proposed by Orion in its submission on the second issues paper. The Authority considers providing for a simple method is desirable for the reasons discussed here.

B.123 We propose that Transpower include in the TPM two different sorts of methods for allocating the annual benefit-based charges for a post-2019 investment between transmission customers:

(a) a standard method or methods for high-value post-2019 investments

(b) a simple method or methods which may be applied to low-value investments.

B.124 The proposed guidelines specify that the simple method should be simpler than the standard method but is defined by reference to the standard method. Overall, the simple approach may forgo some of the narrowly defined efficiency benefits (ie, ignoring transactions costs) of the standard approach, but it reduces administration and transaction costs.

B.125 We are envisaging that Transpower would be pragmatic in allocating the benefit-based charges for low-value investments, with the method of allocation dependent on the nature of the investment. For example:

(a) Transpower could allocate the charges of a low-value investment between load and generation based on the allocation for a related high-value investment

(b) Transpower could allocate the charges to one or a few expected major beneficiaries (eg, those that would otherwise be expected to be materially affected by constraints)

(c) Transpower could use a rough proxy for benefit (eg, load or historical load) to allocate charges

(d) For an investment that is intended to provide benefits to a specific location, Transpower could allocate all the cost of the investment to load (for an importing region) or generation (for an exporting region) in that region. Transpower proposed a method similar to this (its ‘simplified staged approach’) in its submission on the second issues paper. (The major difference is that the regions Transpower defined for applying the charges were very broad. In our view, applying the charges to a broad area would be inappropriate for post-2019 investments, and would be inconsistent with the proposed guidelines because it would effectively spread the charges across all load customers within those very broad regions and thus not result in an allocation which broadly approximates the allocation which would have resulted had the standard method applied.[182]).

(e) For an investment that connects two areas, Transpower could allocate the charges to generation in the upstream region and to load in the downstream region.

(f) For an upgrading investment, Transpower could allocate the charges on the same basis as the charges for the original investment, if the original investment were subject to the benefit-based charge.

B.126 As an alternative to using a simple method to allocate the benefit-based charge for low-value investments, we also considered allocating the cost of those investments to the residual charge.[183] This would spread the cost of low-value investments across all load customers, rather than recovering them from the parties expected to receive the majority of the positive net private benefits.

182 Another key concern that we had with that proposal was that it did not make mandatory the area-of-benefit charge for future investments.

183 Castalia for Genesis proposed this in its submission on the second issues paper.

B.127 In particular, we have considered the argument that low-value and upgrading expenditure is an engineering decision so that the quality and timing of the investment is not influenced by cost. We accept that this may sometimes be the case. However we consider that there will be situations where there are some choices to be made that can and should be influenced by cost considerations. The Authority considers the painting of a wooden house to be an appropriate analogy. While it is clearly necessary to paint the house from time to time to avoid it eventually falling into disrepair, there is still a choice about when to paint it and how to paint it. This choice is influenced by cost considerations.

B.128 For low-value benefit-based investments the incentives to scrutinise Transpower's plans would be weaker. Nevertheless, there will still be stronger incentives than currently exist for Transpower customers to participate during the periods when the MAR and subsequent adjustments to the MAR are determined. In addition, we consider that having a sharp border between the treatment of high-value investments and low-value investments would introduce incentives for transmission customers to seek to have investments sized below the threshold between low-value and high-value investments, for example by breaking investments up into smaller tranches. This has the potential to create significant inefficiencies.

B.129 Instead, applying the benefit-based charge to low-value investments mitigates the potential problem caused by introducing a boundary between low-value and high-value investments.

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

Q20. If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?

B.130 There is a further decision to be made in this area, which is identifying the threshold separating low-value and high-value investments. The Authority has identified two options for particular consideration:

(a) $5 million

(b) $20 million (currently our preferred option).

B.131 An argument for a $5 million threshold would be that further efficiencies could be achieved by requiring application of the standard method to more investments. The Authority in its 2016 TPM proposal took the view that there were likely to be net benefits from a more granular allocation of a benefit-based charge to investments valued at over $5 million. At that time the Authority took the view that the risk that the transaction cost involved in a granular allocation of the charge would exceed the benefit from applying the charge was lower for investments over $5 million (compared to investments valued at under $5 million). At this stage there is little evidence available to us to inform this trade-off. So, subject to the possibility of receiving further evidence in submissions, the choice of the appropriate threshold is a matter of judgement.

B.132 The reason we currently prefer a $20 million threshold is that it would reduce administrative burden on Transpower. A key reason for this is that it would align the threshold with the Commerce Commission’s threshold for ‘major capex’, and so would allow Transpower to rely on information produced for the Commerce Commission’s Investment Test and other cost-benefit analysis when applying the standard method. These sorts of reasons led several submissions on the second issues paper to propose that the threshold be $20m.[184]

Q21.	**What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?**

Share of benefits determined at time of commissioning

B.133 Under the Authority's current proposal, Transpower would determine the share of the benefit-based charge allocated to a transmission customer for an investment at the time the investment is commissioned. Once Transpower has determined this share, it would not change except in exceptional circumstances. This would be the case even if the actual outcome in relation to the benefits obtained by the customer is quite different from the outcome expected at the time the investment was made.

B.134 The benefit-based charge is fixed in this way so that it does not create incentives for grid users to inefficiently avoid transmission charges by altering their use of the grid. Nodal prices should give the customer incentives to use the grid relatively efficiently. So any other charge that is based on use of the grid (such as a per kwh charge) would risk inefficiently discouraging use of the grid. In particular, if the benefit-based charge was correlated with current grid use in some way, this could encourage transmission customers to inefficiently reduce their grid use to avoid the transmission charge, without having any impact on transmission costs. Similarly, if the benefit-based charge was updated to reflect benefits observed to occur in practice, a customer could take costly actions after the investment had been committed to reduce their share of the benefit-based charge (for example, installing distributed generation partly for the purpose of avoiding charges), even though there is no reduction in grid costs. That would be inefficient.[185]

B.135 The proposed guidelines allow some exceptions to the general rule that the allocation does not change, notably:

(a) a substantial and sustained change in grid use

(b) the entry or exit of a transmission customer

(c) a transmission customer changing its point of connection

(d) a partial sale of a business

(e) adjustments resulting from reassignment.

B.136 Although the share of the benefit-based charge generally remains fixed, the benefit-based charge and the annual benefit-based charges for an investment may vary for a variety of reasons. For example, if a transmission customer disconnects but the fall in use of an investment is not sufficient to trigger a reassignment, then the other customers who paid the benefit-based charge on the investment would see their charges increase correspondingly. Similarly, if any of the costs in the covered cost change (see clause 14 of the proposed TPM guidelines (appendix A)), the charges could change.

184 For example, Castalia for Genesis, Genesis Energy, PwC for 14 EDBs, Transpower

185 As Hogan (2011), page 13 says, "The cost allocation is made ex ante based on the same analysis that is and must be made before the investment goes forward. The cost allocation does not depend on the ex post utilization that actually occurs, which is difficult to even define much less measure. This ex ante perspective is particularly significant in the context dealing with uncertainty."

B.137 Furthermore, the charges could vary as a result of any of the changes to an allocation discussed in paragraph B.135 above. For example, if there is a reassignment, the charges would vary both as a result of the reassignment and as a result of any reallocation that results from it, as discussed in paragraphs B.192 and B.193 below.

Allocators for initial set of pre-2019 investments pre-determined

B.138 We have included in schedule 1 of the proposed guidelines an allocation between transmission customers of the costs of each of the seven recent major investments in clause 13(b) of the proposed guidelines The Authority considers that there are three options for the use of this allocation:

(a) the allocation could be purely illustrative, with Transpower being required to determine the allocation for the seven recent major investments

(b) the allocation could be a default option, which Transpower is permitted to depart from

(c) Transpower could be required to set benefit-based charges based on the allocation in schedule 1 (this is currently our preferred option).

B.139 We have proposed setting these allocations because we wish to facilitate the early implementation of the new TPM. Because we expect the new TPM to better meet our statutory objective than the existing TPM, an early implementation would ensure that the gains associated with the new TPM are achieved earlier. After discussions with Transpower on the workability of our proposal, we have come to the view that requiring Transpower to apply our allocation may be expected to reduce the administrative burden and therefore enable earlier implementation.

B.140 We are considering two broad options for determining the allocation of the seven recent major investments in clause 13(b) of the proposed guidelines:

(a) use of the vSPD model – as discussed immediately below (currently our preferred option and the one we have used to produce the current schedule to the guidelines)

(b) use of an approximate regional method – as discussed after the discussion of the vSPD model.

vSPD method

B.141 We are proposing an allocation to each customer in respect of each investment in proportion to that customer's share of the positive net private benefits resulting from the investment, estimated using vSPD (the Authority's version of the Scheduling, Pricing and Dispatch model). In compiling schedule 1 to the guidelines, we estimated the historical investments' benefits based on changes in the price and quantity of energy at various nodes occurring as a result of each grid investment, calculated by running the vSPD model. The method we have used is described in more detail in appendix H.

B.142 We have made every effort to ensure that the method used for the schedule 1 allocation is robust and objective. However, our allocation is not perfect; in producing it we have necessarily made a number of simplifications and judgements. But perfection is not a necessary feature of cost allocation.[186] In our view, the cost allocation for the investments in schedule 1 approximately reflects the distribution of benefits from those investments. The Authority considers that this allocation of costs will result in a more durable TPM compared to the current guidelines.

186 See paragraph B.157 to B.167 for further discussion of this point.

Approximate regional method

B.143 We have also considered an alternative method of allocating the costs of the seven major investments in clause 13(b) of the proposed guidelines. This alternative (which we call the ‘approximate regional method’) involves allocating the costs of each historical investment amongst generators and load based on judgement as to where their benefits approximately fall.

B.144 This method involves grouping beneficiaries of grid investments according to whether they are load or generation customers and also the location of each customer in one of the four regions that Transpower uses to allocate its current RCPD charge: upper North Island (UNI), lower North Island (LNI), upper South Island (USI) and lower South Island (LSI).

B.145 The approximate regional allocation for the historical investments, together with the engineering judgement that underpins that allocation, is set out in the following table.

Table 13 Benefit-based allocation of costs under approximate regional approach

Investment	Proposed allocation		Reasoning: benefits of each investment
	Generators	Load	
North Island Grid Upgrade (NIGU)	30% non-UNI generation	70% UNI load	Reduces constraints between UNI and rest of NZ Allows UNI load greater reliability of supply and lower energy prices Allows non-UNI generation to access higher energy prices
UNI Reactive Support	30% non-UNI generation	70% UNI load	Similar to NIGU, this investment effectively increases the UNI stability constraint limit We have applied same allocation as for NIGU
Wairakei Ring	45% LNI generation, 15% SI generation	40% NI load	Allows LNI generators (and also SI generators to a lesser extent) to access higher energy prices Lower energy prices for load across North Island
Bunnythorpe-Haywards Reconductoring		25% LNI load, 75% SI load	Prevents constraint on southward flow from central North Island to LNI (and on to South Island) during dry periods Lower energy prices for load across LNI and all of South Island
HVDC link	50% SI generation	40% NI load, 10% SI load	In normal (wet) conditions, provides North Island load with lower energy prices and allows SI generation to access higher North Island prices In dry years, lower prices for South Island load Provision of ancillary services: widespread benefits
LSI Renewables	25% LSI generation	75% SI load	Improves access to load for LSI generation Relieves constraint on import of energy into LSI in dry year, reducing dry year prices for LSI load Relieves constraint on import of energy into USI, reducing prices for USI load

Investment	Proposed allocation		Reasoning: benefits of each investment
LSI Reliability	25% LSI generation	75% LSI load	Relieves constraints, allows LSI generation to export greater quantity of energy Increases import capacity and reliability into LSI load

B.146 While the approximate regional method could be seen as a pragmatic and simple solution, we are not proposing it, as we consider that it may create boundary issues and, unlike the vSPD method, it relies on judgement to apply the principle that a customer's charges should reflect its benefits from each grid investment. The vSPD method is also preferable because it gives a finer grained analysis and doesn’t spread charges across each region.

Q22. What are your views on the Authority’s proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?

We propose recovering the costs of three historical investments via the residual charge

B.147 The vSPD model has been used to allocate the costs of seven of the major investments commissioned largely since 2004 that had an approved value over $50 million at the time the investment was approved. However, for the remaining three investments that meet these criteria (North Auckland and Northland (NAaN), Otahuhu Substation Diversity and Upper South Island Reactive Support) our vSPD modelling was not able to identify material benefits for transmission customers commensurate with the costs of these investments.[187] As is discussed in paragraph B.67 we do not consider it appropriate for grid users to pay benefit-based charges that exceed the benefits of the investment for pre-2019 investments, since there is no decision to be made about whether to proceed with the investment.[188]

B.148 There is therefore a decision to be made about how the costs of these three investments should be allocated. We see there being three broad options:

(a) recover all costs of these three investments through the residual charge, rather than the benefit-based charge (currently our preferred option)

(b) use of bespoke methods to allocate costs through the benefit-based charge; for example:

(i) for NAaN: allocate 50% of costs to upper North Island (UNI) load customers (recognising this investment will likely benefit these customers in future given increasing demand in the area) and 50% through the residual charge

(ii) for Otahuhu Substation Diversity: allocate costs to UNI load customers (we calculate around 16% of costs) based on expected (probability-weighted) benefits derived by assuming a probability of a future outage of the Otahuhu substation, and the remaining 84% through the residual charge

(iii) for USI Reactive Support: allocate 50% of costs to upper South Island (USI) load customers and 50% through the residual charge

187 This may in part be a result of calculating the benefits over an historical period.

188 For efficient post-2019 investments, the expected benefits necessarily exceed the expected cost.

(c) a mixed approach under which some proportion of costs are recovered through the benefit-based charge, with the balance being recovered through the residual charge. Depending on the circumstances of each investment, recovery for each investment could be in a range from wholly benefit-based to wholly residual charge, with mixed options in between depending on the outcomes of further analysis.

B.149 We are proposing that the costs of the remaining three investments be recovered entirely through the residual charge, rather than adopting bespoke allocation methods. This is based on our view that relying solely on the vSPD allocation approach is reasonable for pre-2019 investments.

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

Transpower to develop method for allocating benefit-based charge

B.150 As Transpower has responsibility for developing the TPM, proposing new transmission investments and implementing the benefit-based charge on these investments, we consider that it is appropriate for Transpower to develop the methods for allocating charges (including both standard and simple methods) for post-2019 investments.[189] In particular, Transpower already needs to estimate the electricity market benefits of some investments when it develops investment proposals. In developing allocation methods for the benefit-based charge, Transpower will be able to build on the information generated as part of the investment proposal process to identify the likely beneficiaries of each investment and the relative value of the benefits each is expected to receive.[190]

B.151 In developing its method, Transpower may need to grapple with similar issues to those the Authority has considered in determining its proposed allocation for the historical investments in schedule 1 of the guidelines. For example, the Authority envisages that Transpower may make assumptions about the wholesale electricity prices that would occur in the scenario in which the relevant grid investment is not made (the counterfactual scenario). In doing so it would need to take into account demand response (which is expected to be stimulated by real-time pricing).

Trading off accurate benefit estimation against other considerations

B.152 Transpower would in principle need to consider all the benefits that the grid provides to customers, as outlined in paragraph B.101 above. Some submissions argued it would be difficult or complicated to accurately assess benefits, that the outcome would be sensitive to modelling assumptions[191] and that the outcome might be complex and contentious.[192]

---

189 We identified a number of methods on pages 98 and 99 of the second issues paper. There is also a useful discussion of different possible methods in Pérez-Arriaga et al 2014.

190 Hogan (2011), page 2, comments that “In many instances, estimating the shares of benefits is easier than estimating the benefits.”

191 For example, submissions on the supplementary consultation paper by Covec, Counties Power Consumer Trust, Entrust, Northern Federated Farmers, Top Energy, Trustpower, Vector, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Counties Power, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower, Fonterra, Entrust, Transpower, Northpower, Oji Fibre Solutions, IEGA, Pioneer Energy, NZ Energy, Otago Chamber of Commerce

192 For example:

B.153 However, the proposed guidelines allow Transpower to use a proxy for net private benefits in allocating the benefit-based charge between customers under the standard method,[193] provided that, in Transpower's reasonable opinion, the proxy results in an allocation of the benefit-based charge to each designated transmission customer who receives a major positive net private benefit from the benefit-based investment that broadly approximates the allocation that Transpower considers would have resulted had expected net private benefits been used to calculate the allocation. In addition, the various proposals discussed in the section headed *General matters* above mean that Transpower will need to take account of pragmatic considerations in calculating and allocating benefits.[194]

B.154 On the other hand, the proposals discussed in the section headed *General matters* above, such as the need to avoid incentivising transmission customers to avoid transmission charges in ways that cause economic efficiency, would limit the ways that Transpower will be able to allocate the charges.

B.155 One of the arguments raised against the benefit-based charge has been that, unless a robust way of identifying beneficiaries can be developed, the charge would incentivise parties to argue that they should not be identified as beneficiaries.[195] However:

(a) parties will have a countervailing incentive because, if they claim not to benefit from an asset, Transpower may decide not to proceed with the proposal.

(b) other parties in favour of a proposed investment would have incentives to put forward information to support the opposite case to avoid paying a higher share of the costs of the investment that benefits them.

(c) the proposals discussed in the section headed *General matters* above mean that when Transpower designs the TPM, it will need to take account of practical considerations, such as concerns around robustness (for example, ensuring an appropriate trade-off between accuracy and practicality).

(d) as the methods will be part of the TPM, the only way they could be changed would be through changing the TPM, which the Authority would only approve if doing so promoted the Authority's statutory objective.

- submissions on the supplementary consultation paper by Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Pacific Aluminium, Top Energy, Trustpower, Vector
- submissions on the second issues paper by Axiom for Transpower, EA Networks, Network Waitaki, PWC for 14 EDBs.

193 Transpower's submission on the second issues paper proposed that a proxy be used (Appendix B, clause 8). In its submission on the second issues paper, Bushnell for Trustpower made the point that a proxy could be useful to deal with issues such as these.

194 This is similar to the proposal in the supplementary consultation paper that the standard method must be as accurate as reasonably practical, which was supported by a number of submitters on it, including: PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Meridian Energy, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower. Other submitters such as Axiom for Transpower and Transpower opposed it as being meaningless and unworkable. For the reasons outlined in this section, we do not agree.

195 For example, Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Top Energy, Trustpower, Vector in submissions on the supplementary consultation paper, and Axiom for Transpower, Bushnell for Trustpower, EA Networks, HoustonKemp for Trustpower, Pioneer, Powerco, Transpower, Unison in submissions on the second issues paper and PWC for 14 EDBs(p.7), Fonterra (p.5), Transpower (CEG) (p.81), Trustpower (Bushnell) (p.5), ENA (p.10), Powerco (p.5), Westpower (p.7), Trustpower (p.17) in submissions on the options working paper.).

B.156 Furthermore, stakeholders would have an opportunity to assist in developing suitably robust methods as part of the consultation that takes place during the development of the TPM. In addition, for high-value investments, the Authority is proposing that Transpower consult with interested parties about important parameters that determine the charges. This consultation should reveal information relevant to establishing the benefits of the investment.

Impact of approximations in estimation of benefits

B.157 Various parties have raised the concern that getting a precise estimate of who benefits from a transmission investment and by how much will be difficult.[196] We agree. Furthermore the precision of the allocation will be affected by:

(a) the need to take account of pragmatic considerations as discussed in the previous section

(b) the use of a simple method for allocating charges for low-value investments.

B.158 This means that the allocation of charges may only approximately reflect benefits, and, that despite the measures taken to improve robustness, there may continue to be a significant range of uncertainty around Transpower's estimates of benefits.

B.159 Some submitters suggested that the benefit-based charge would not provide a forward-looking price signal, because beneficiaries will be unable to reliably estimate the way that charges will change as a result of new investments.[197]

B.160 Other submitters suggested that experts had identified that the AoB charge (now the benefit-based charge) would become less accurate over time, which might lead to a loss of durability.[198]

B.161 In our view, this does not undermine the case for allocating charges according to net private benefit. Perfection and total objectivity are not features of workably competitive markets and should not be expected from the methods for the allocation of the benefit-based charge. Even with a high degree of approximation, we consider that the benefit-based charge would still provide much better incentives for grid users than is possible under the current guidelines.[199]

---

196 For example, submissions on the second issues paper by Transpower, Scientia for Transpower, Bushnell for Truspower.

197 For example, submissions on the supplementary consultation paper by Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Top Energy, Trustpower, Vector, Trustpower, Houston Kemp for Trustpower, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, The Lines Company, Top Energy, Waipa Networks, Westpower, Axiom for Transpower.

198 For example, submission on the supplementary consultation paper by Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Top Energy, Trustpower, Vector.

199 See Hogan (2011), pages 8 and 14. Hogan explains:

> If [an investment is only just efficient], and the estimate of incremental benefits approximately equals the total cost, it may be difficult to allocate the costs and support the investment well enough to preclude substantial opposition from the supposed beneficiaries. Less than perfect estimation of the benefits and their distribution could be problematic. Even with transmission mandates, this may lead to some such expansions failing to go forward. This would be a loss. From a societal perspective, however, this would not be much of a loss because by assumption the investment is about a net zero benefit.
>
> The more interesting case is where the net benefits are substantially greater than the transmission cost. If voluntary merchant investment is not forthcoming, efficient investment could follow the mandatory route with regulated cost allocation. An important observation is that in these cases cost allocation may by definition not require perfection in the estimation of the benefits or the distribution of benefits. By assumption, in this case there is a substantial excess of benefits F+G+H over the cost TC. Furthermore,

B.162 Furthermore, as Hogan (2011) states:

> Treatment of uncertainty is not simple, but it is unavoidable. The investment decision and cost allocation both can utilize the expected values of benefits and costs across a range of conditions. The scenario analysis is an approximation, but this is not fatal for either the investment evaluation or the cost allocation. The existence of uncertainty does not imply or require cost socialization.

B.163 In principle, this is no different from the uncertainty faced by a private investor undertaking investment in load or generation. That is, net benefits expected at the time the investment is committed may not materialise in practice. It is still appropriate to charge transmission users for the cost of investments made on their behalf, since they will then take that uncertainty into account in making their own decisions.

B.164 An allocation of transmission charges that turns out to be wrong in hindsight is unlikely to cause significant inefficiencies in decisions about access to or use of the grid once the decision is made. Transmission charges are typically a relatively small part of the cost of selling and purchasing electricity, so a substantial change in transmission charges would cause a much smaller change in the charges consumers pay for using electricity. More importantly, a party can only avoid paying the charge for any grid investment if it disconnects from the grid. It would only do that if its total benefit from access to the grid was less than its charges for accessing and using the grid (which is less likely).

B.165 In addition, the benefit-based charge for high-value investments is designed to reduce the chance that charges exceed net private benefits. These design features include:

(a) allocating the charge to both load and generation to the extent they are expected to benefit from an investment

(b) allocating the charge to all or the major expected beneficiaries from an investment

(c) providing for the charge to be recalculated where there is a substantial and sustained change in grid use

(d) allowing reassignment if certain criteria are met

(e) providing for the charge to be recalculated when there is damage to a grid investment

(f) restricting charges on pre-2019 investments to the estimated benefits they provide

(g) providing for a prudent discount in some circumstances where disconnection is otherwise likely.

B.166 The practical challenges of a benefit-based approach are not insurmountable. Each of the three ISOs or RTOs we met in the United States operates a beneficiaries-pay approach which is used to allocate the costs of at least some grid investments. The approach used in these jurisdictions involves modelling the forecast benefits of investments using system planning software models. While the scope of coverage for benefit-based charges and the

---

in the absence of contracts, the regulators have the added advantage that the private interests of market participants diverge from efficient investment in ways that could make cost allocation easier rather than harder.

We agree with Hogan.

NERA for Meridian made the similar point that it is not necessary to aim for a high level of precision in identifying beneficiaries. (submission on second issues paper).

.

methods used in these jurisdictions differ from the approach proposed in New Zealand, the benefit-based principle is the same.[200]

B.167 Our assessment is that the difficulties and uncertainties involved in using net private benefits to allocate transmission charges do not undermine the case for allocating benefits in that way.

Substantial and sustained change in grid use

B.168 As is discussed above, in the normal course of events, the allocation of the benefit-based charge for an investment amongst transmission customers would be established when it is commissioned and then not changed.[201] However, there are some circumstances in which it may be appropriate to vary the allocation during the life of a high-value investment, specifically where the circumstances which have eventuated were not factored into the calculations used to allocate the relevant charges. We expect that these events would be rare. We expect for example that such an adjustment would be no more common than reassignment.

B.169 In workably competitive markets, parties to long-term contracts typically include provisions to deal with substantial changes of circumstances. Often those provisions require the parties to work in good faith to re-establish the commercial basis of their agreement. Although the presence of such provisions can create incentives for opportunistic behaviour, carrying on with manifestly inappropriate arrangements can also create inefficiencies. We have therefore included provision for altering the allocation of the benefit-based charge in such unforeseen circumstances. The TPM must include a proposed method for revising allocations if such a change has occurred. However, no such revisions to charges would be available for low-value investments, in keeping with the need to have a simple benefit-based charge for low-value investments.

B.170 If Transpower did adjust the allocation of the benefit-based charge following a finding that the circumstances which have eventuated were not factored into the calculations used to allocate the relevant charges and that such circumstances are expected to be sustained, it would not affect the requirement to recover the covered cost of an investment from the beneficiaries collectively. This is because the proposed guidelines explicitly include the reassignment provision to deal with circumstances where a substantial reduction in use of the investment has occurred.

B.171 The reassessment process should also help address concerns raised by some submitters regarding ‘free riding’ or ‘free-loading’ (for example, the risk that some parties might misrepresent their expected benefits from an investment when it is proposed in order to reduce their level of charges).[202] The Authority is of the view that, to the extent that there would be such problems with the benefit-based charge, such problems would be much less than under the status quo, under which generators do not pay, and cost recovery is spread through the interconnection charge.

[200] Costs have been allocated on a beneficiaries-pay basis for around 50 projects by PJM and five projects by MISO. NYISO has yet to commit a project, but has two ‘public policy’ investments in process with recovery expected to be 75% by beneficiaries-pay and 25% socialised. See *Beneficiaries-pay in USA*, Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018.

[201] As outlined in paragraph B.96, some of the parameters used to estimate the annual benefit-based charge may change, but this would not alter its allocation between customers.

[202] For example, see Bushnell for Trustpower’s submission on the TPM options working paper (p.5).

B.172 There is a risk that a review process could encourage participants to inefficiently avoid the benefit-based charge, because it would give parties incentives to alter their behaviour to demonstrate that they would benefit less from the investment and so reduce future charges for themselves should a review take place. The fact that the timing of future reviews would be uncertain is likely to reduce the likelihood of such behaviour.[203] Nevertheless, to further reduce the chances of such distortion occurring, the proposal limits the circumstances that can qualify as a substantial and sustained change in grid use.

B.173 First, the proposed guidelines provide that before the provision is invoked, there must be a substantial and sustained change in grid use. The TPM must explain how Transpower will determine when such a change has occurred. For example, it may specify a materiality threshold, perhaps defined in terms of a change relative to regional demand.

B.174 Second, the proposed guidelines provide that the circumstances must be outside the range of circumstances factored into the calculations used to allocate the relevant charges. This is because an outcome within the range of circumstances factored into the calculations will have been taken into account in deciding the initial allocation of the benefit-based charge. We anticipate that the investment approval process will continue to contemplate a wide range of scenarios. A substantial change is something that was not factored in to the relevant calculations during that process.

B.175 An example of the latter would be if Transpower had calculated charges using a weighted average of the benefits from two scenarios, one in which some customers experienced rapid demand growth, and another in which customers experienced slower growth. If demand growth turned out to be zero (that is, even lower demand than in the slow-growth scenario), that would be considered outside the range of initial circumstances contemplated and so might trigger a substantial change of circumstances review. But demand growth that was intermediate between that in the two scenarios would not trigger a review.

Q24. Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?

203 For this reason, we do not agree with the submission by Meridian on the second issues paper that the benefit-based charge should be subject to periodic review.

Implementation timeframe for the benefit-based charge

Proposal

Clauses 27 - 29, proposed TPM guidelines (appendix A)

Discussion

B.176 The Authority is proposing the benefit-based charge be implemented in 'one go' to all the high-value benefit-based investments (other than those that are identified as a result of implementation of Additional Component E). This is because the benefit-based charge will initially apply to only a small number of investments, and, depending on the outcome of this consultation process, the share of charges that each designated transmission customer is to pay for each pre-2019 investments (aside from those included via Additional Component E) may have already been determined in schedule 1 of the proposed guidelines.

B.177 We propose that Transpower is to delay the implementation for low-value post-2019 investments and to delay implementation of most of the additional components if that is necessary to facilitate the application of the charge to high-value investments. Although delaying the implementation of the benefit-based charge delays the efficiency gains from these measures, it facilitates faster implementation of the benefit-based charge for new high-value investments, which should achieve the related efficiency gains more quickly. Also, it is likely to be more straightforward to phase in the benefit-based charge for low-value investments after the standard charge has 'bedded in', as this allows time to address any implementation issues before the charge is implemented for low-value investments.

B.178 Nevertheless, we intend Transpower to implement the benefit-based charge for low-value investments as soon as practicable after it is implemented for high value investments. The proposed guidelines state that these charges must be implemented within 5 years of the commencement of the TPM.

B.179 As the residual charge recovers all recoverable revenue not otherwise recovered by the TPM (or a lesser amount determined by Transpower) any revenue foregone from phasing in the simple benefit-based charge method would be recovered through the residual charge.

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

Upgrading expenditure

Proposal

Clauses 30 - 32, proposed TPM guidelines (appendix A)

Discussion

B.180 If Transpower undertook expenditure that is expected to extend the life of an investment beyond its initially expected life (or if it has been previously re-estimated, the re-estimated life) or otherwise add to the benefits from the investment ('upgrading expenditure'), the definition of a benefit-based investment means that the expenditure would be treated as a new benefit-based investment.

B.181 However, treating each upgrading expenditure as a separate investment could result in a proliferation of different benefit-based investments. Accordingly, we propose that

Transpower would also be able to treat the upgrading expenditure as additional capital expenditure on the existing investment. In this case, Transpower would first calculate the annual benefit-based charge for the new combined investment, and allocate the charges across customers on the basis of the present value of the sum of the benefits *previously* estimated for the existing investment plus the additional benefits estimated to result from the upgrading expenditure.[204]

B.182 Transpower would in general not be permitted to make changes to the requirement to recover the covered cost of the investment to be upgraded or to the pre-existing assessment of each customer's benefits from that investment. The reason for this is discussed in paragraph B.133 and B.134 above. However, as outlined in paragraph B.135 above, the proposed guidelines do provide for adjustments in some circumstances (eg, if there is a new entrant).

B.183 While Transpower would be permitted to apply the method in paragraph B.181 above to a pre-2019 investment, it is not obvious how it would do so in practice. The difficulty is that the benefit-based charge for the original investment would be recovered over time using the Commerce Commission method, and the benefit-based charge for the upgrading investment would be recovered using IHC. Instead, Transpower may choose to leave the treatment of the pre-2019 investment unaltered, and treat all post-2019 upgrading expenditure as one or more separate investments that are recovered according to IHC.

Reassignment

Proposal

Clauses 33 - 38, proposed TPM guidelines (appendix A)

Discussion

B.184 The proposed guidelines require Transpower to provide for reassignment of some of the costs of a benefit-based investment from the benefit-based charge to the residual charge.[205] This occurs when a grid investment turns out to be a 'white elephant' and customers make significantly less use of it than Transpower had anticipated initially. This reassignment is achieved by reducing the value of the relevant grid assets for the purposes of calculating benefit-based charges in respect of that investment. The intention is to ensure that the

---

204 That is, customer j's charge for the upgraded investment could be calculated as follows:

Let: variables with the subscript j refer to those variables for customer j, and variables without subscripts refer to totals for all transmission customers benefitting from the investment

C(O) = covered cost of the original investment not yet recovered at time upgrading expenditure is commissioned

B(O) = present value of net positive private benefits of original investment originally estimated to be recovered after the date the upgrading investment is commissioned

C(U) = covered cost of the upgrading investment

B(U) = present value of net positive private benefits now estimated to result from the upgrading expenditure

Then the present value of customer j's benefit-based charge

$$= \frac{B(O)_j + B(U)_j}{B(O) \;\; + B(U)} * (C(O) + C(U))$$

205 This provision is in place of the provision for 'optimisation' that was included in the 2016 TPM proposal. We have changed the terminology to reduce the confusion that may be caused by the term 'optimisation', which is used in other contexts and has a different meaning. When we comment on the views expressed in submissions on the 2016 TPM proposal on reassignment, we are referring to the views that were expressed on optimisation.

future charges paid by the investment's beneficiaries better reflect the charges they would have paid had the services provided by the investment been more accurately forecast.[206]

B.185 Investments below $5 million are not eligible for reassignment in order to ensure a relatively simple benefit-based charge regime for such small investments. The $5 million threshold is proposed (rather than making the threshold for reassignment the same as the $20 million threshold for high-value investments) to ensure that, for example, relatively small distributors have access to reassignment where they have suffered a reduction in load that is not large overall but that is significant to them.

B.186 A potential disadvantage of reassignment is that it could lead to inefficient grid investment decisions. This is because a customer that would benefit from a proposed grid investment may anticipate the possibility of reassignment in the event that the grid investment turns out to be a white elephant. Such a customer might then have an inefficiently weak incentive to carefully assess the benefits against the costs of the grid investment. This could result in overbuilt investments in the interconnected grid. However, our view is that this effect is likely to be small, as we expect reassignment to be a rare event. As a result, this potential cost is likely to be outweighed by the advantages of the proposed reassignment provisions.

B.187 Reassignment allows transmission pricing to be more like what would occur in a workably competitive market. For example, suppose that a customer disconnected from the grid for some reason. In a workably competitive market, the contractual terms between the supplier of services (Transpower in this case) and the customer would determine whether the supplier or the customer would bear the loss on any investment that was stranded or significantly underutilised due to the disconnection. It would be unusual for other customers of the supplier to bear any of the cost.

B.188 We have proposed the reassignment provisions of the guidelines for the following reasons:

(a) to reflect the reduction in service provided where there has been a significant change in circumstances (such as significant technological development or reduction in demand) such that the 80% threshold is met, and that is likely to be sustained

(b) to efficiently manage the risk of asset stranding (in circumstances where the 80% threshold is met), and so reduce investment uncertainty, by providing customers with an assurance that there is a limit to how much direct additional cost they will have to bear as a result of other customers changing their use of the benefit-based investment.

B.189 For a period of time specified in the TPM (for example purposes, 10 years) after a post-2019 benefit-based investment is commissioned, reassignment would not be available unless a single customer disconnects, causing the value of the investment following reassignment to drop by 20% or more. The different treatment of post-2019 investments from pre-2019 investments is intended to ensure that customers do not seek to have new investments 'gold plated' because they know that reassignment is available. This objective is achieved by specifying that a long period of time must elapse after such a post-2019 investment has been commissioned before Transpower can write it down. This period must be sufficiently long that the prospect of reassignment does not distort incentives.

B.190 Transpower would include a method for determining what the value of the investment would be following reassignment in the TPM.[207] In our view, the considerations under the heading

206 The reassignment provisions allow for non-transmission customers to apply for reassignment, as submitted by Fonterra in its submission on second issues paper.

General matters above would mean that the procedure for determining the reduction in value may be relatively simple, perhaps using a rule of thumb, even if that means that the reduction is not precise.[208] It might for example adjust the value before reassignment by making an estimate of the degree of economies of scale in all transmission investment, and use that to reduce the value based on the reduction in required capacity of the investment (for example, it might be estimated that a 50% reduction in capacity typically means a saving of 20% in costs).

B.191 If the conditions for reassignment are not met, then the reassignment provisions do not apply, so that Transpower will be required to recover the full covered cost of the investment. For example, if a customer exits but the fall in demand is not substantial enough that the investment's value following reassignment falls to less than 80% of its current value, then the benefit-based charges of other customers are increased proportionally such that 100% of the value of the investment continues to be recovered through the benefit-based charge. Transpower is required to remove reassignment if it is no longer justified.

B.192 If reassignment occurs (so the value of assets in an investment is reduced) the annual benefit-based charge for the investment would be reduced correspondingly, and its allocation would be adjusted to reflect the change in use that led to the reassignment.

B.193 For example Transpower may choose to make adjustments as follows:

(a) To the extent that the reassignment is due to the disconnection of a transmission customer, the benefit-based charge would be allocated among the remaining transmission customers paying the benefit-based charges for the investment according to the net benefits that were originally assessed.

(b) To the extent that the reassignment results primarily from a change in use by a distributor caused by the disconnection or change in use of its customers:

(i) the benefit-based charge is to be allocated among the transmission customers according to the net benefits originally assessed, except that:

(ii) the benefits originally assessed for the distributor would be reduced in accordance with the benefits it is now assessed as getting.

Q26. Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge? What are your views on the proposed reassignment provisions?

---

207 For the avoidance of doubt, this reduction in asset value is for TPM purposes only and has no effect on the value of the asset recorded in Transpower's RAB.

208 This is the reason that we have not referred to optimisation of the investment. Optimisation is normally much more involved than the relatively simple process we are envisaging.

Main component 3: residual charge

Proposal

Clauses 39 - 41, proposed TPM guidelines (appendix A)

Discussion

Function of the residual charge

B.194 The function of the residual charge is to allow Transpower to recover any remaining maximum allowable revenue (MAR) that it is not able to recover from all of the other charges in the TPM. In particular it would recover:

(a) costs attributable to pre-2019 investments in the interconnected grid that are not recovered using the benefit-based charge

(b) Transpower's unallocated costs (including overhead expenses)[209]

B.195 We are considering two options: providing in the guidelines for a single residual charge or for multiple residual charges so that there is a separate residual charge for each sub-component of residual costs (for example, one residual charge for unallocated costs, one for costs attributable to investments in the interconnected grid that are not recovered using the benefit-based charge, one for costs that result from reassignment, and so on).[210] We are currently minded to provide for a single residual charge, as this approach may reduce administrative burden.

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

Design of the residual charge

B.196 The residual charge is not intended to actively influence grid use and investment (including investment in transmission alternatives). It does not need to, because, as is discussed in appendices D and E, this is done by other elements of the TPM and existing institutions, including:

(a) the electricity spot market, which provides efficient incentives for short-term use of the grid via nodal prices (as discussed in appendix D)[211]

(b) potentially a transitional peak charge, which the proposed guidelines provide for if it would better meet the Authority's statutory objective

(c) the Commerce Commission's regulatory regime and the proposed benefit-based charge, which together should limit incentives for inefficient investment by grid users and in the interconnected grid.

209 Transpower's unallocated costs (including overheads) for owning and operating the transmission grid amounted to $198 million in the financial year 2015/16. Under the current TPM, these costs are recovered from:

- generator customers, through the HVDC charge and the connection charge
- load customers, through the interconnection charge.

210 This has the effect of addressing the proposal by Oji Fibre Solutions (submission on the second issues paper) to have a separate optimisation charge to recover costs arising from reassignment.

211 The real-time pricing (RTP) project is intended to further enhance the efficiency of the spot market.

B.197 Since the mechanisms outlined in the previous paragraph are intended to influence grid use and investment to promote efficient grid use and investment, any additional price signal is therefore likely to cause inefficient use of the grid or inefficient investment.[212] As a result, we have designed the residual charge so that it affects the use of and investment in the grid as little as possible. This will be achieved if a grid user cannot profitably take actions that affect the residual charge it pays. If instead, for example, the residual charge was allocated based on real-time supply or demand, that would encourage grid users to inefficiently alter their grid use.[213] That is why we are proposing the charge be allocated based on a customer's historical electricity demand,[214] rather than its ongoing demand. Specifically, we are proposing the residual allocator could be based on data collected over at least two years ending prior to 1 July 2019. Using a historical allocator gives the customer little incentive to change its use of the grid purely for the purpose of reducing the size of its residual charge.

B.198 The Authority considers that this meets the concerns of those submitters[215] who suggested that the design of the residual charge should minimise inefficient avoidance of charges, but at the same time not discourage efficient consumption decisions.

B.199 We therefore disagree with those submissions that suggested that the residual charge might be more efficient if it sends a price signal[216], for example to adopt non-transmission solutions, to avoid the residual charge, to avoid inefficiently early grid investment or to signal the long-term cost of building network capacity. In our view, any such signal would most likely detract from efficiency.

Q28. **Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?**

212 This is illustrated by the CBA, which shows that removing the RCPD charge brings forward grid investment, which improves efficiency.

213 See, for example, Hogan and Pope (2017), page 76

214 It is for this reason that we do not agree with those submitters who suggest that the residual allocator should be adjusted more frequently than we have proposed to respond to changing circumstances. See for example PWC for 14EDBs on the second issues paper.

However, we have not included an option of using physical capacity. This takes account of submissions on the second issues paper that using physical capacity would be undesirable, because charges would be based on a level of capacity that is unlikely to be ever fully utilised and that would vary significantly between customers (See, for example, Fonterra, NZ Energy, PwC for 14 EBDs, Waipa Networks, Westpower).

215 For example, submissions on the second issues paper by Pacific Aluminium, New Zealand Aluminium Smelter, Oji Fibre Solutions, Winstone Pulp, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, Transpower.

216 See for example, Contact Energy, ENA, KCE, Mighty River Power, NZ Steel, Oji Fibre Solutions, PWC for 14 EDBs See also, for example, submissions on the supplementary consultation paper by Nova, Oji Fibre Solutions, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central.

Allocation of the residual charge

B.200 In determining our proposed default residual allocator, we have considered various measures of historical demand, each of which has pros and cons.

B.201 One choice is whether to allocate based on a peak measure, such as AMD, or a measure of broad usage, such as annual electricity consumption. A potential disadvantage of using AMD is that a load customer might pay less (assuming that the transmission charges were passed through in distribution charges) if it were embedded than it might pay if it were grid-connected. This potential artificial advantage could distort load customers' decisions on location and connection.

B.202 By contrast, an allocator based on annual electricity consumption has the advantage that it treats grid-connected and embedded load customers in the same manner (which would reduce distortion to location and connection decisions). This would address the legitimate concerns of those submitters[217] who considered that AMD disadvantages grid connected grid users relative to those who connect behind, and can therefore benefit from, the averaging implicit in a distributors' AMD. On the other hand, it may have a relatively greater impact on price-sensitive customers (and so distort such customers' decision-making). Large industrial consumers, for example, tend to have a demand profile with less pronounced peaks compared to households, so an allocator based on annual consumption would have a relatively greater effect on an industrial than an AMD allocator.

B.203 We are also considering a two-stage mixed approach to the residual allocator: a pre-allocation between direct connects and distributors using AMD, followed by a further allocation amongst direct connects and amongst distributors using annual consumption. This approach may have the advantages of both impinging relatively less on price-sensitive customers, and also minimising distortions to location and connection decisions by load customers.

B.204 Our current preferred option is to base the residual allocator on historical AMD, as this may reduce the likelihood of disconnection of some large loads. An allocator based on AMD would be less likely (than a MWh allocator) to cause the disconnection of a large industrial consumer (as such consumers tend to have relatively flat load profiles).

B.205 A number of submitters on the supplementary consultation paper either did not support the use of AMD[218] or thought Transpower should be given greater flexibility[219] to design the charge, or thought that the allocator should be RCPD[220]. Various reasons were given, including: that RCPD would limit wealth transfers and that AMD is unworkable in practice, results in illogically high charges, is punitive, is too narrow and is retrospective and so unlawful. For reasons given elsewhere, we do not agree that AMD is retrospective or unlawful. However, in recognition of the fact that we may not have identified the best allocator, we have provided that Transpower may use another method if that would better meet our statutory objective.

217 For example submission on the supplementary consultation paper by Oji Fibre and Winstone Pulp International.

218 For example, IEGA, NZ Energy, Pioneer Energy, Otago Chamber of Commerce, NZ Steel, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower, Fonterra.

219 For example, IEGA, NZ Energy, Pioneer Energy, Otago Chamber of Commerce, Meridian Energy, Oji Fibre Solutions, Norske Skog, Auckland Airport.

220 For example, Norske Skog, Nova.

B.206 The proposals discussed under the heading *General matters* above and the heading *Provisions relating to adjustments* mean that Transpower would need to consider the various potential inefficiencies discussed above in the detailed design of the charge. For example, it could calculate the part of a distributor's residual charge attributable to large load connected to it as if the large load was grid-connected at the distributor's point of connection.

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

AMD for a customer with multiple points of connection

B.207 If we decide to allocate based on AMD, a further issue arises as to how to measure AMD for a customer that has more than one point of connection. There are two options:

(a) a 'non-coincident peak' measure of AMD, that is, measure demand at the (different) times of highest demand for each point of connection separately and allocate a separate share of the residual charge for each point of connection (then sum to get the customer's overall share of the residual) (This is currently our preferred option.)

(b) a 'coincident peak' measure of AMD, that is, measure demand at the (single) time of highest combined demand for all points of connection within a single 'location' (where location is indicated by the 3-letter location code used by Transpower in its pricing disclosure) and allocate the customer's share of the residual charge on that basis.

B.208 Compared to option (a), option (b) will generally result in a lower measure of AMD – and a lower residual charge – for a customer that has more than one point of connection. This is because the peaks at each point of connection may not occur at the same time. Some parties have submitted that it is reasonable for a customer to be able to take advantage of having a diverse customer base in their location.

B.209 Our view is that the residual charge should be allocated in proportion to a customers' size (and so reflective of their likely willingness and ability to pay). As is discussed in appendix D: decision making framework, allocation of common costs in this way is consistent with what would occur in a workably competitive market. Our current view is that a 'non-coincident peak' measure of AMD is a better proxy for the size of the customer base in a location and its ability to pay charges, however, we are open to considering arguments for the alternative approach.

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

Net load or gross load for the residual allocator

B.210 A further choice is whether to adopt a net load or gross load approach to measuring the default residual allocator.

B.211 Some submitters on the supplementary consultation paper[221] thought that we should adopt a net load approach. Some of these submitters thought that the load measure should at least be net of direct generation that is commissioned or committed before the proposed guidelines are finalised. Reasons given included that a gross load would impose a tax on parties with co-generation, and that a decision to invest in co-generation was normally undertaken for good commercial reasons rather than to avoid the charge.[222]

B.212 However, other submitters on the supplementary consultation paper[223] considered that netting off committed direct generation would not be service based or cost reflective.

B.213 Our current preferred option is that the residual should be allocated based on a gross load approach, as gross demand is a better proxy for customers' size (and so their willingness and ability to pay) than net demand. As is discussed in appendix D: decision making framework, allocation of common costs based on this is consistent with what would occur in a workably competitive market. If the operation of distributed generation reduced the residual charge, the allocation would no longer be based on customer size or ability-to-pay. It would also risks creating an artificial incentive for investment in distributed generation over time, in advance of the residual allocator being updated (particularly if updating occurred frequently).[224]

B.214 We do not intend to add back demand response to AMD in calculating gross AMD. While adding back demand response might be desirable in principle for the same reason that adding back distributed generation might be desirable, we accept the views of some submitters on the second issues paper that adding back demand response may be impractical.[225]

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

221 For example, Fonterra, Nova, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

222 In practice it is impractical to determine the extent to which actions are taken to avoid a charge and actions that are taken for commercial reasons other than to avoid the charge. As a result, we cannot realistically design the guidelines to distinguish between these two different sorts of motivations.

223 For example, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

224 This means that we are inclined to disagree with those submitters who suggested that the capacity measure should be net of distributed generation; eg, the submissions by Network Waitaki, NZ Energy, Norske Skog, PWC for 14 EDBs on the second issues paper.

225 See for example the submissions on the second issues paper EnerNoc, Orion.

B.215 Finally, if a gross load approach is adopted, there is a question as to whether demand should be 'grossed up' for injection by distributed generation only, or by both distributed generation and behind-the-meter generation. Our current preferred option is that demand should be grossed up for distributed generation and also for behind-the-meter generation, as we see no compelling reason to treat these types of generation differently for these purposes.

Q32. **If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?**

B.216 We have considered whether there is sufficient information available for Transpower to implement a gross load approach in the way we are proposing. The Authority considers that there is data available from the Reconciliation Manager that would meet the requirements of these provisions of the proposed guidelines. The guidelines require Transpower to use this data. The Code already provides for Transpower to request any data from the Reconciliation Manager that it requires in order to set transmission charges.

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

Default or predetermined residual allocation

B.217 An alternative option would be for the Authority to determine the initial allocation of the residual charge in advance. We have allocated the residual charge for the purposes of the indicative transmission charges as reported in chapter 5. Under this alternative option, that indicative allocation (with adjustments as appropriate) would become a default or required allocation in the guidelines, for example, by setting out the allocation as a new schedule 2 to the guidelines. We are not currently minded to adopt this option, as we see no compelling reasons to do so and this is a matter of implementation which Transpower is able to address.

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

Adjusting the residual allocation

B.218 The guidelines set out a principle that in allocating the residual charge, Transpower should adjust the allocation where a customer has experienced a substantial change to demand due to factors over which they have no control. This principle is intended to allow, for example, a downward adjustment to the AMD of a distributor where a large industrial customer that was previously connected to the distribution network has closed down. An example is the exit of the Holcim cement plant, which reduced demand on Buller Electricity's distribution network. In our view, to charge such a distributor high charges based on a high level of demand, when the industrial customer that caused that level of demand has since closed down, would be perceived as unfair (and so would undermine the proposed TPM's durability).[226]

[226] This addresses the concerns expressed by some submitters on the second issues paper that historical data may not be a good proxy for the customers current size; see for example PWC, Westpower.

Q35. Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?

B.219 The proposed guidelines allow Transpower to propose another residual allocator if that would better satisfy the Authority's statutory objective.[227] In practice, this would mean that a different residual allocator would have to satisfy the proposals discussed under the heading *General matters* above and the heading *Provisions relating to adjustments* These are likely to put significant constraints on any residual allocator that Transpower proposes.

B.220 Transpower could update the residual allocator through an operational review of the TPM, to avoid the allocator becoming anomalous as grid conditions evolve. A number of submitters on the 2016 TPM proposal expressed concerns that allowing for revision of the residual allocator might lead to inefficiencies as grid users altered their behaviour in anticipation of the revision.[228] However, we have provided for this update to be based on the definition of allocator on AMD from the later of 10 years prior to the date of update or the date of publication of the second issues paper. The Authority considers that this should in large part avoid creating inefficient incentives for avoidance of the charge and for inefficient investment in or operation of distributed generation.[229]

Charge would recover overheads

B.221 It is proposed that any remaining overheads and unallocated operating expenses (after the attribution discussed in paragraph B.73 above) would be recovered through the residual charge. Some submitters on the 2016 TPM proposal considered that the overheads should be recovered through the area-of-benefit charge or through a surcharge on all the TPM charges.[230] Other submitters suggested that overheads should be recovered through the residual charge.[231]

B.222 Our view is that the recovery of overheads should reflect how they would be recovered in a workably competitive market.[232] In our view, since the residual charge uses load size as a proxy for ability to pay, it is most appropriate to recover overheads and remaining unallocated operating expenses through the residual charge.

Charge would apply to load only

B.223 Some submitters on the supplementary consultation paper suggested that we should provide for or consider charging the residual to generation as well as load. However, our current preference is that the residual charge would apply to all transmission customers but only to the extent that they are load. Generators would be liable to pay the charge only to the extent that they off-take electricity from the grid. If Transpower proposes an alternative residual allocator, that allocator would need to have the same effect.

B.224 The reason the Authority proposes restricting the charge to load is to avoid inefficiency. Any residual charge that is applied to generation (that is, injection into the grid) would likely

---

227 This accords with Transpower's submission on the second issues paper, which proposed that Transpower have broad discretion in choosing the residual charge allocator in developing the TPM.

228 For example, Bushnell and CEC for Trustpower, EA Networks.

229 This is also the reason we do not agree with those submitters on the 2016 TPM proposal who suggest there should not be such a lag; eg, Buller Electricity, Fonterra, PwC for 14 EDBs, TECT, Top Energy.

230 For example, Oji Fibre Solutions, Pacific Aluminium

231 For example, Meridian.

232 This accords with the view expressed by Pacific Aluminium in its submission on the second issues paper.

largely be passed on to load in the form of higher energy prices, since new generators would then delay entering until the energy prices they expect to receive would cover their residual charge. That is, on average, prices would rise relative to the no-charge case before the next generator would find it profitable to invest. This means that effectively load customers would likely end up paying much of the charge whether or not the legal incidence of the charge is on load or generation. Since the charge would be passed through in nodal prices, it means that nodal prices would likely be higher, discouraging energy use (compared with the case where the entire charge is on load). The Authority considers that this would be inefficient.

B.225 We therefore do not agree with those submitters on the 2016 TPM proposal who suggest that both load and generation should pay the charge.[233] The reasons given why generators should pay the charge include:

(a) It is desirable to strengthen the locational price signal generators face (Waipa Networks). As is noted above, we consider other charges provide appropriate price signals.

(b) Both load and generation benefit from access to the market (Counties Power). We agree, which is why the benefit-based charge applies to both load and generation.

(c) Competition will limit the ability of generators to pass through the residual charge (EPOC, Norske Skog).

We disagree with these arguments for the reason outlined above.

B.226 The reason the Authority proposes that the charges apply to both load and generators to the extent that they are load is to avoid creating any classification or other difficulties when a customer is sometimes a load customer and sometimes a generator.[234]

B.227 Submitters had mixed views about how specific we should be about the measure of load for this proposal. In its submission on the supplementary consultation paper, Transpower considered that this section of the proposal should be removed, because it should not prescribe that the residual charge be allocated on the basis of load. We believe the proposed guidelines give Transpower considerable flexibility on how to choose the residual allocator, while making clear that the general principle is to avoid applying the residual charge to generators.

B.228 Other submitters on the supplementary consultation paper[235] thought this proposal too vague, because the size of a customer's load can be measured in several different ways. We believe it is desirable to give Transpower flexibility to propose the allocator that it considers best advances our statutory objective, so as to avoid precluding some allocator that may better meet our statutory objective than AMD.

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

[233] These include Counties Power, ENA, EPOC, Fonterra, Orion, Pacific Aluminium, PwC for 14 EDBs, Waipa Networks, Vector. On the other hand, Contact Energy and Meridian (including NERA) consider load should pay the residual charge.

[234] This also addresses the submission of TECT and Top Energy on the second issues paper that parties should be classified from load to injection if their power flow changes on a permanent basis.

[235] For example, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

Addressing dilution of price signals from pass-through of residual charge

B.229 Some submitters have expressed concern the residual charge would be passed through to mass-market consumers through variable consumption charges, which would artificially discourage electricity use. We agree that this could cause inefficient use of the grid. This issue is being addressed through the Authority's review of distribution pricing.

The residual charge is expected to reduce over time

B.230 The amount to be recovered under the residual charge would vary from time to time based on the following factors:

(a) The amount of revenue to be recovered on pre-2019 investments will decline over time as they depreciate.[236]

(b) Transpower could choose to recover an amount through the residual that is less than the maximum it is entitled to (for example, if it wanted to ensure that transmission remained competitive with an alternative, such as solar panels).

(c) If Transpower chooses to extend the benefit-based charge to cover more investments as provided for under Additional Component E*,* then the residual charge would decline correspondingly.

(d) The residual will be affected by differences between the Commerce Commission’s method for valuation of assets and recovery of investment costs over time (DHC) and the approach proposed in this paper (IHC).

(e) Any reassignment would reduce the total of the benefit-based charges, increasing the amount to be recovered via the residual charge.

B.231 Overall, the residual charge is likely to decline over time, as the value of interconnection assets not covered by benefit-based charges depreciates. Conversely, the value of investments covered by benefit-based charges will grow over time.

---

[236] Revenue recovered through the residual charge will not increase due to new investments in the interconnected grid or upgrading expenditure, as these costs are recovered through the benefit-based charge.

Provisions relating to adjustments

Proposal

Clause 42, proposed TPM guidelines (appendix A)

Discussion

B.232 The purpose of these provisions is to allow for adjustments to be made to the benefit-based and residual charges where circumstances change or else to scale back charges where they would result in Transpower over-recovering its revenue

B.233 Clause 42 of the proposed TPM guidelines deals with large consumers or generators and with the sale of a business.

Charges for a new large consumer or generator

B.234 The proposed guidelines require Transpower to include in the TPM a process for allocating benefit-based charges and residual charges in respect of a new large consumer or generator or an existing large consumer or generator that substantially increases its use of the grid,[237] and therefore also for adjusting the allocation of the benefit-based charges between customers to the extent necessary to take account of the charges paid by the new large customer.[238]

B.235 The proposals discussed under the heading *General matters* above mean that the rules will need to be designed to minimise the chances of inefficiently affecting the customer's decisions about the location and size of its connection and about its use of the grid. In particular, this means that it would be problematic to base the new entrant’s transmission charges on its capacity or use of the grid after it enters. If charges were based on this, it would have an inefficient incentive to reduce its capacity or use, purely to avoid the charges.[239] Instead, we think it likely that the charges for new customers will have to be based on a proxy or proxies.

B.236 It is important, once the new entrant has entered, for it to be treated from that time in a similar way to a (possibly hypothetical) existing business that was otherwise identical to the new entrant, but was connected to the grid at the date of publication of the 2019 issues paper. To do otherwise would potentially introduce a production inefficiency. For example, if the new entrant had lower charges than it would have had if it had been an existing business, it might be able to out-compete an existing business (when it might otherwise have been less competitive). This would be inefficient.

B.237 Similarly, the proposed guidelines require Transpower to include in the TPM rules for determining changes to transmission charges for a transmission customer that electrically connects a new large consumer indirectly to the interconnected grid. The reason for making

237 This responds to the submission of Pacific Aluminium on the second issues paper that a customer making a permanent change to its demand should be treated the same as a new customer. Its submission with respect to disconnecting customers is dealt with by the reassignment provisions.

238 This provision deals with the concern expressed by PowerCo in its submission on the second issues paper that the substantial change in circumstances provision may not be sufficient to ensure that the benefit-based charge responds efficiently to the entry of major load and generation. It also addresses the submission by Axiom for Transpower that the previous proposal did not address how customers that enter an area of benefit after an investment has been made would be assigned a share of those sunk assets.

239 Transpower makes a similar point on page 8 of its submission on the second issues paper, although the context is different (namely, the allocation of charges to generation based on average injection).

an adjustment to the distributor's charges when a new large customer connects to a distribution network is that otherwise there would potentially be an inefficient incentive for a large customer to embed in cases where direct connection would have been more efficient. As before, consequential adjustments to the allocation of the benefit-based charges between customers would be necessary to take account of the charges paid by the new large customer.

Adjustment for a large consumer that shifts its connection point

B.238 The proposed guidelines require the TPM to avoid creating inefficient incentives for a large consumer or generator to shift its point of connection from or to Transpower and/or a designated transmission customer.[240] Without such a provision, the proposed TPM could encourage large electricity consumers to shift their connection point in order to avoid or reduce their residual charge and potentially their benefit-based charge. For example, a directly connected industrial customer might be encouraged to disconnect from the grid and embed if this means it would avoid paying transmission charges. This could be inefficient.[241]

B.239 The proposed guidelines do not prescribe how Transpower is to achieve this.[242] The provision could provide, for example, that Transpower would adjust the charges of the affected distributor(s) and the large consumer so that the charges applying to or attributed to the large consumer move with it. For example, in the case of a Transpower customer that will become embedded in a distribution network, the provision could provide that Transpower would increase the distributor's charges by the customer's charges.

B.240 While the prudent discount policy might be one potential tool for addressing these inefficient incentives, our intention is that it is the tool of 'last resort'. Rather than simply reducing charges for any customer that is able to shift its point of connection, Transpower is required to design the other elements of the TPM to avoid creating incentives for customers to shift their point of connection. This means Transpower should not need to have recourse to the prudent discount policy to address this issue.

Adjustment for partial sale of a business

B.241 The proposed guidelines provide that the TPM is to make provision for Transpower to reallocate the transmission charges a transmission customer is liable for if it becomes aware that the customer has sold part or all of its business (eg, industrial plant). Transpower would split the charges between the existing customer and the new owner as appropriate. The purpose of this provision is to ensure that in that circumstance the charges continue to reflect the relative benefit that each party gets from access to the interconnected grid.

B.242 Absent this provision, the contract between the buyer and seller could provide for allocating responsibility for transmission charges, and this could be reflected in the price paid by the

---

240 This proposal addresses the submission of Refining NZ on the supplementary consultation paper that the cap could result in incentives for users such as the refinery becoming direct consumers.

241 In its submission on the second issues paper, NZ Steel made the point that it might have an inefficient incentive to change its GXPs to allow for consolidation with Counties Power. This proposal addresses this issue.

242 This addresses Transpower's submission on the supplementary consultation paper that the draft guidelines in that paper were too prescriptive on this issue. It also responds to the submissions on the supplementary consultation paper that suggested that the more prescriptive approach proposed there may not be practical. For example, see submissions by PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

new owner. However, this could result in an anomalous situation, for example, where the existing customer retained responsibility for all of the transmission charges relating to that part of the business and the new owner paid Transpower nothing.

The charges may need to be scaled back

Proposal

Clauses 43 - 45, proposed TPM guidelines (appendix A)

Discussion

B.243 These provisions, together with Clause 9 of the proposed guidelines, prevent the total of all transmission charges from exceeding the maximum revenue that the Commerce Commission allows Transpower to recover. If not for these provisions and Clause 9, this could occur as the result of the cost recovery profile that the proposed guidelines would set as the default for post-2019 investments (the IHC approach). This is because the benefit-based charge will eventually extend to all investments in the grid and in the later years of each investment's life, the benefit-based charge would exceed the recoverable revenue attributable to the investment.

B.244 It is also possible that Transpower may decide to recover less than its maximum allowable revenue. For example, it might choose to reduce a particular customer's charges in order to be competitive in the face of emerging technologies that compete with transmission. In that case, it would not be appropriate to recover the charge from other customers by increasing their residual charge.

B.245 We have proposed (in Clauses 43 – 45, proposed TPM guidelines (appendix A)) a way to scale back charges that we consider best promotes our statutory objective.

B.246 There are a variety of methods that Transpower could choose to scale back the benefit-based charges. For example, for pre-2019 investments, it could:

(a) reduce the benefit-based charge pro-rata in order to preserve the relativity between the benefit-based charges in different locations, or

(b) disproportionately scale back the benefit-based charges for those pre-2019 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 it would distort locational decisions by providing incentives for generation and load to locate away from the non-core grid.

B.247 Transpower would need to select a method that is consistent with our statutory objective.

Q37. **Are the proposed provisions relating to adjustments appropriate?**

Main component 4: prudent discount policy

Proposal

Clauses 46 - 48, proposed TPM guidelines (appendix A)

Discussion[243]

General rationale for granting prudent discounts

B.249 The economic rationale for granting prudent discounts is that the discounts avoid large inefficiencies in situations that can be characterised as 'win-win'—that is, granting the discount avoids economic inefficiencies arising from the flat-rate nature of the benefit-based charge and residual charge, and avoids other transmission customers paying higher transmission charges.

B.250 For example, it can be better for all transmission customers that an applicant pays discounted transmission charges (exceeding incremental costs) if the alternative is that the applicant would disconnect from the grid and pay no transmission charges. Provided the customer receiving the prudent discount was paying at least its incremental cost, the first scenario is likely to be a better outcome for all transmission customers because the applicant would be making some contribution towards common costs, whereas in the second scenario it makes no contribution, resulting in higher charges for other transmission customers. In effect, the PDP is a practical alternative to applying an efficient Ramsey pricing formula.[244]

B.251 Prudent discounts allow Transpower to reduce its charges to customers when that is considered to be necessary to meet the market costs of an alternative to transmission assets. This is what would happen in a workably competitive market.

A prudent discount would be available to applicants for whom it is privately beneficial to disconnect from the grid and source alternative supply

B.252 This provision largely carries over the policy intent in the current TPM relating to the prudent discount policy (PDP). That is, it provides that Transpower can discount a customer's charges where it is privately beneficial for the customer to undertake a project that will allow it to bypass the existing grid, even though it is not efficient to do so. In addition, the proposed guidelines extend the PDP to situations where it is privately beneficial for a party to disconnect from the grid and source an alternative supply of energy, even though it is not efficient to do so.[245]

---

243 There was a large measure of support from submitters on the supplementary consultation paper for retaining the PDP and for extending it as outlined in the proposed guidelines, largely for the reasons discussed here.

244 The second issues paper discussed using Ramsey pricing calculations to allocate the residual charge, as an alternative to extending the PDP to cover the risk of large load customers disconnecting from the transmission grid. However, it concluded that it was impractical.

Partly for this reason, we do not accept the views of those whose submissions on the second issues paper suggested that the need for a PDP indicates that there are problems with the Authority's proposed TPM; eg, Auckland Airport, EMA, Norske Skog, Refining NZ, TECT, Transpower, Vector.

245 The current prudent discount policy does not fully cover this situation, as it explicitly excludes scenarios where a party might source supply from new generation. This is because the definition of 'alternative project' in the TPM means an investment proposed by a customer, which if implemented, would bypass existing grid assets, but does not include proposed new generation.

B.253 Some submitters viewed it as unlikely that industrial load customers would disconnect from the grid and self-supply. Our view is that, in that case, prudent discounts would not be granted to applicants. However, we are aware that the risk of disconnection because of the ability to self-supply is not just a risk in relation to industrial customers. Some distributors also are in a position where self-supply may be a commercially viable option (and if not now, then maybe in the future as a result of changing technology and business models).

B.254 Other submitters expressed concern that prudent discounts might be granted in situations where an application lacked credibility.[246] Submitters were also concerned that the criteria for the PDP might be too difficult to meet.[247] Our view is that these would be matters for Transpower to consider in developing the TPM. Under the proposed guidelines, the TPM would set criteria for assessing applications and calculating discounts under the PDP.

Prudent discounts would apply for the life of the asset unless otherwise agreed

B.255 We have considered two options for the duration of a prudent discount:

(a) this decision could be left unspecified (so that it is to be agreed via commercial negotiation between Transpower and its customer)[248]

(b) the guidelines could specify that it applies for the life of the relevant asset unless the parties agree otherwise (currently our preferred option).

B.256 Some direct consumers have indicated to the Authority that PDPs do not provide enough certainty to make long-term investment and operational decisions.

B.257 Under the proposed guidelines, a prudent discount would apply for the expected life of the asset to which the discount relates, unless a shorter period is otherwise agreed between Transpower and the party receiving the prudent discount.

B.258 This would give a party greater certainty that a prudent discount will be available for the full life of its investment, thus reducing unnecessary uncertainty and promoting efficient investment. It would also reduce the transaction costs involved in assessing applications for new prudent discounts at the end of their term.

Q38. **Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?**

246 For example, PwC for 14 EDBs

247 For example, Contact Energy, Oji Fibre Solutions, Refining NZ

248 In its submission on the supplementary consultation paper, Transpower suggested that the term of a prudent discount should be agreed by the parties, because making the life of the asset the default term effectively forces Transpower into very long-term agreements unless the customer decides otherwise.

Cap on transmission charges[249]

Proposal

Clauses 49 - 53, proposed TPM guidelines (appendix A)

Discussion

B.260 The price cap is intended to limit increases in customers' 'capped transmission charges', being all transmission charges other than the ones excluded by clause 49 of the proposed TPM guidelines (appendix A). Essentially this means the cap limits increases in charges due to the reallocation of existing transmission costs resulting from the proposal.

B.261 One option is for the TPM not to include a price cap. This option would introduce benefit-based charges that better reflect customers' benefits from the seven major investments without delay and for that reason could promote durability and efficiency.

B.262 However the Authority's current view is that the TPM should include a price cap. There are three reasons why the Authority believes a cap is warranted:

(a) Certainty—because the proposed guidelines give Transpower some flexibility (for example, through the provisions discussed under the heading *General matters* above), customers would otherwise be left uncertain as to what their charge would be. A cap would provide customers with relative certainty in advance.

(b) The prudent discount for exit is restricted to circumstances in which customers seek alternative supply (it is not available if a customer goes out of business) — we want to reduce incentives for other forms of inefficient exit (such as a customer going out of business) as a result of the introduction of the new TPM. However, we don't want to extend the prudent discount policy to do this. So an alternative is to use the cap to limit the initial impact of charges by allowing businesses that might otherwise exit time to adjust to the new charges. For a number of direct customers, the cap would be binding and would remain binding for many years.

(c) Limiting potential efficiency effects that might arise from price shocks—limiting the initial impact of the charges would mitigate concerns that the TPM proposal would result in unexpected increases in charges. In particular, some submitters suggested the proposal's wealth transfers could create uncertainty, reduce investor confidence, affect the durability of the TPM, or in some other way have an adverse effect on efficiency.[250] A transition could help address this, to the extent it is an issue.

Options for implementing a price cap

B.263 A price cap could be implemented in various ways. We are considering two options for capping charges.

B.264 The first option (currently our preferred option) would result in the increase in each distributor's capped transmission charges over the transmission charge it pays in 2019/20 being limited to no more than 3.5 percent of the estimated total electricity bill of all of the consumers supplied, directly or indirectly, from the distributor's network in the 2019/20

249 The inclusion of a cap in the guidelines addresses Transpower's submission on the second issues paper that there should be a transition to deal with price shocks.

250 For example, submissions on the second issues paper by EA Networks, Infratil, Mighty River Power, Norske Skog, Transpower, Vector.

pricing year, increased by the rate of inflation plus the percentage increase in the distributor's load (if any) since the 2019/20 pricing year.

B.265 This proposal gives distributors the ability to cap the initial real increase in their customers' transmission charges to about 3.5 percent[251] of their 2019/20 total electricity bill. However, because distributors have discretion in how they set charges, it does not prevent distributors from choosing to disproportionately pass on the increase in charges to particular groups of consumers.[252]

B.266 For each direct consumer, the price cap would result in the increase in each direct consumer's capped transmission charges over the transmission charge it pays in 2019/20 being limited for 5 years to no more than 3.5 percent of the total estimated electricity bill of the direct consumer in the 2019/20 pricing year, increased by the rate of inflation plus the percentage increase in the direct consumer's load (if any) since the 2019/20 pricing year. After 5 years, the 3.5 percent would increase by 2 percentage points per annum (that is, to 5.5 percent, then 7.5 percent etc, until such time as the cap no longer limits the direct customer's capped transmission charges for at least one pricing year). This would ensure that the charges for those customers would become cost-reflective over the long run. This is appropriate as it:

(a) limits the inefficiency that could arise from otherwise similar transmission customers facing different charges

(b) ensures that direct consumers will eventually face cost-reflective charges.

B.267 The cap would be on (and so limit increases in) capped transmission charges rather than on the total electricity bill faced by a direct consumer, even though the cap would be specified in terms of the estimated total electricity bill.[253]

B.268 Transpower has sought more specific guidance on how to implement the cap. In order to address this concern, we have proposed a prescriptive approach to the calculation of the price cap, setting out in the proposed guidelines the data that Transpower must use in setting the cap and the formula that it must apply.[254] The estimated total electricity bill of all of the consumers supplied from each distributor's network and for each direct consumer is to be estimated using data from the reconciliation manager, from the Commerce

251 Because the cap is based on estimated electricity bills, the cap may differ somewhat from 3.5% of consumers' actual bills. However, the difference is not likely to be material.

252 In its submission on the supplementary consultation paper (page 8 and page 16), Transpower comments that "the design of the price cap means Transpower could not provide surety prices would be within the 3.5% price cap." Similarly, other submitters (eg, Vector, Entrust, Pioneer Energy, Otago Chamber of Commerce) note that the price cap relies on retailer pass-through, which may not happen. We agree with these points. The important point is that the cap would give distributors and retailers the discretion to limit the price increases. Whether they choose to or not is a matter for them.

253 This accords with the suggestion of submitters on the supplementary consultation paper who stated that in order to have a meaningful impact, the cap should apply to transmission charges, not to the total retail bill. For example, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, Nova, Oji Fibre Solutons, The Lines Company, Top Energy, Waipa Networks, Westpower.

254 This also responds to those submitters on the supplementary consultation paper who stated that the cap is unworkable or difficult to apply or too complex possibly because it is highly dependent on assumptions or relies on Transpower being aware of information it may not have access to (for example, the total retail bill of all consumers at a network level). For example, PwC, Alpine Energy, Aurora Energy, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower, Transpower, Ngawha Generation.

Commission's Electricity Distribution Information Disclosure Determination 2012 and from Transpower's own data about transmission charges.[255] In addition, we note that the considerations discussed under the heading *General matters* above mean that Transpower would need to develop a method for implementing the cap which takes account of any remaining practical difficulties in estimating the electricity bill.

B.269 This calculation formula for the estimated total electricity bill leaves out a number of relatively small components of the electricity bill (notably retail margins and metering charges). We have done this to make the estimated electricity bills simple to calculate. The effect is the same as if we had set the cap at a percentage somewhat less than 3.5%. That is, the cap gives distributors whose charges are restrained by the cap greater protection against price increases than the description of the cap would otherwise imply.

B.270 Some submitters on the supplementary consultation paper[256] made the point that there is a trade-off between allowing prices to change quite quickly (so limiting the benefits outlined in paragraph B.262 above), and prolonging the transition period, which potentially delays the efficiency gains from having prices better reflecting costs and, they say, placing an unfair burden on those who subsidise others under the current TPM. Some submitters on the supplementary consultation paper considered a cap would be likely to distort outcomes by shifting costs to others, impacting negatively on durability over time.[257] Other submitters on the supplementary consultation paper supported the introduction of a price cap as a transition.[258]

B.271 Other submitters have proposed different transitional methods than the proposed cap. For example:

(a) amend the existing RCPD charge to give a more suitable locational price signal, develop and introduce an AoB charge, develop and transition the residual charge as a postage stamp charge, develop and introduce LRMC, remove RCPD, and then adjust the AoB charge if necessary[259]

(b) a staged introduction of a new TPM with price increases staggered over several years[260]

(c) a transition from the RCPD charge to the residual charge.[261]

---

255 If these data are not available at the time Transpower first applies the cap, it may have to use estimates of them and then apply a wash-up when they become available.

256 For example, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central.

257 For example, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower, Pioneer Energy, Otago Chamber of Commerce, Counties Power, Counties Power Consumer Trust.

258 For example, Fonterra, Westpower, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central. Genesis Energy, Castalia for Genesis, Transpower, Oji Fibre Solutions also agreed that transitional provisions are desirable.

259 For example, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Counties Power, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower.

260 For example, Top Energy, Ngawha Generation.

261 ENA, Alpine Energy, Aurora Energy, Buller Electricity, Counties Power, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower, Unison, Centralines.

B.272 We accept that some of these approaches would result in a transition similar in nature to that which we are trying to achieve with the cap. However, we cannot see any particular advantage that any of the proposed approaches provide relative to the cap that is set out in the proposed guidelines.

B.273 We agree with the submitters that it is a matter of judgement whether the benefits of the cap outlined in paragraph B.262 above outweigh the costs it imposes such as the muting of the price signals from any new TPM in the interim.[262] However, we believe we have limited any adverse efficiency effect of the proposed cap by applying the cap to the customer's capped transmission charge. Roughly speaking, this means that it would limit the increase in the customer's transmission charges that are attributable to pre-2019 investments in the interconnected grid listed in schedule 1 of the proposed guidelines.

B.274 Specifically, the cap would not apply in regard to charges attributable to assets commissioned after the end of the 2019/20 pricing year, any peak charge or any kvar charge, as doing so would materially reduce the efficiency of those charges. Neither would the cap apply to any increase in a distributor's or direct consumer's charges as a result of reassignment or a review under the substantial and sustained change in grid use provision.

B.275 Of these, the most material exclusions are likely to be the charges attributable to assets commissioned after the end of the 2019/20 pricing year. If these investments are efficient, these charges are not expected to adversely affect any customer, since the charges each customer would pay for them would be less than the benefit it is expected to derive from them.[263]

B.276 The cap would not apply to any benefit-based charge for further assets included as benefit-based investments under Additional Component E. Instead, Transpower would be able to propose a transition for the application of the benefit-based charge to such investments (including a transition that would have the same effect as an extension of the cap to the charges for these investments), if that were consistent with clause 12.89 of the Code. We have not specified the transition, as the appropriate form may depend on the investments Transpower chooses to include.

Q39. **Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?**

B.277 Some submitters on the supplementary consultation paper suggested that the cap should be calculated using transmission charges only, in part because it would be unusual to impose a price cap on transmission costs that is relative to total energy costs.[264]

B.278 We are also considering such an option. In this, the price cap would be the same as discussed above, except that, instead of limiting charges to a percentage of the estimated total electricity bill, the price cap would instead limit increases in capped transmission charges for any transmission customer to no more than some fixed percentage of the

262 This point was also made by Pacific Aluminium and New Zealand Aluminium Smelter in its submission on the supplementary consultation paper.

263 Some submitters on the supplementary consultation paper (eg, Trustpower, Houston Kemp for Trustpower) proposed that the price cap should apply to more than the capped transmission charges. We disagree, for the reasons outlined in this paragraph and paragraph B.273.

264 For example, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, Counties Power, Counties Power Consumer Trust, Meridian, Pacific Aluminium, New Zealand Aluminium Smelter.

customer’s capped transmission charges in 2019/20 expressed in $/MW (based on the customer’s historical AMD). This is a simpler approach because it avoids the need to estimate consumers’ electricity bills.

B.279 We are not proposing this option because we consider that the electricity bill is more salient to consumers than transmission charges implicit in it. If we adopted this option, it would make the impact of the proposal on load customers’ (and mass market consumers’) total bills less consistent, as grid charges make up a different proportion of the total bill for each customer.

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

B.280 We considered applying the price cap to generators’ charges as well as load customers’ charges. Such a cap could be specified as a percentage of generation revenue in 2019/20, with the limit gradually increasing over time (as it does for direct connect customers). This would ease the transition to the new regime for North Island generation customers that currently do not pay transmission charges and would do so under the proposal.

B.281 However, our currently preferred option is to apply the proposed price cap to load customers only. This is because we consider that the concerns about certainty and price shocks that are discussed in paragraph B.262 above mainly arise with respect to the potential impact on consumers (residential, and direct consumers), rather than generators. Generators would not be subject to the residual charge under this proposal (except to the extent of their load), which would limit the adverse impact on generators from our proposal.

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

B.282 We also are considering options for how Transpower might recover any revenue forgone as a result of the operation of the cap.

B.283 Our current preference is to fund the price cap through a percentage surcharge on the total of benefit-based charges for pre-2019 investments and residual charges. This would mean that, to the extent that some customers’ increases in transmission charges are capped, the transmission charges of other designated transmission customers (both load and generation) would increase a little compared to what they would have paid but for the cap. This does not violate our proposal that benefit-based charges for any one of these investments should be less than the private benefits from the investment, since we expect that the estimated benefits from the investment would substantially exceed the increase in charges caused by the operation of the price cap.

B.284 The other option we are considering is to fund the price cap out of the residual charge. So to the extent that some customers have their charges capped, all other customers’ charges would increase slightly as a proportion of their load.

B.285 We prefer the surcharge on the total of the benefit-based charge for pre-2019 investments and the residual charge because the purpose of the cap is to mitigate any price shock from the new TPM and to create a transition from the current TPM to the new TPM. This is better achieved if generation as well as load bears some of the cost during the transition. We accept that if the surcharge on generators was substantial and persisted for some time, it would likely be passed through to some extent to load in energy prices, and so potentially could cause some inefficiency in grid use. However, we expect this inefficiency to be minimal, both because the surcharge is likely to be small and because we expect the surcharge to diminish over time. Instead of all transmission customers funding the capped amounts, a variation would be for the surcharge to apply only to those who would gain under the proposal, in terms of a reduction in transmission charges. The premise for this option does not take account of the fact that those who would gain from the proposal, in terms of reduced charges, would argue they are currently supporting those who under the proposal would pay more. It may also mean greater allocative inefficiency for longer, compared to a low, flat surcharge on all customers. Thus the Authority does not currently favour this option.

Q42.	**How should the price cap be funded?**

B.286 It may be that after the new TPM is introduced, it becomes apparent that the cap is having little impact on some distributors and/or direct connect customers. In that case there would be little point in continuing with the cap for these customers. Accordingly, the proposed guidelines include a proposal that a customer’s cap be removed if in any pricing year after the year of first application of the benefit-based charge to post-2019 low-value investments, the cap does not have the effect of reducing transmission charges for that customer.

Additional components[265]

Proposal

Clause 54, proposed TPM guidelines (appendix A)

Discussion

B.287 The proposed guidelines require Transpower to propose each additional component if doing so would, in its reasonable opinion, better meet our statutory objective.

B.288 As a result, if Transpower proceeds with any of the additional components, they should have net benefits.

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

265 These proposed guidelines omit the proposal in the draft guidelines published with the second issues paper for a 'marginal savings' adjustment mechanism. Many submitters, such as Transpower, were not convinced of the desirability or workability of this proposal. Transpower, for example, considers that it would be better to remove the proposal from the guidelines altogether (Transpower's submission on the supplementary consultation paper, page 14).

Additional component A: staged commissioning

Proposal

Clause 55, proposed TPM guidelines (appendix A)

Discussion

B.289 This proposal relates to investments that are commissioned in stages (staged commissioning), that at some stages meet the definition of a connection asset, but eventually meet the definition of an investment in the interconnected grid. As some submitters[266] pointed out, the treatment of these investments has been clarified in the decision in *Vector Ltd v Transpower New Zealand Ltd* [2014] NZHC 3411. For this reason, it is not necessary to clarify the treatment of these investments in the TPM.

B.290 Charges are based on whether an asset met the definition of a connection asset at the time the charges were being applied, and not on the ultimate configuration or purpose of an asset.

B.291 This creates the risk that participants may have an incentive to seek to avoid staged commissioning, in order to avoid incurring connection charges. Our proposal would make these incentives weaker, compared to the current TPM. Under our proposal, it is likely that the costs of a redesign of the investment (to avoid it meeting the connection definition) would be met to a significant degree by the potential connection customer. This is because it is likely that the costs of the asset, once fully commissioned, would be met through the benefit-based charge, and it is likely that the customer receiving temporary connection services would also be subject to this charge.

B.292 The proposal in clause 55 of the proposed guidelines is intended to assist in mitigating any remaining inefficient incentives to avoid staged commissioning. It does so by allowing Transpower to adjust the split of charges for the investment between the period when it meets the definition of ‘connection assets’ and the later period after it has become an interconnection asset.

B.293 The benefit-based charges would, over the investment’s life, recover the covered cost of the investment less any connection charges already paid for the investment.

[266] For example, Transpower’s submission on the second issues paper (Appendix B, comment on connection charge at clause 5), PWC.

Additional component B: charging for assets principally providing connection services

Proposal

Clause 56, proposed TPM guidelines (appendix A)

Discussion

B.294 The relevant definitions in the current TPM (in particular, connection link, connection node, interconnection link and interconnection node) rely on the physical and electrical configuration of assets, except in the definition of 'grid asset'.[267] The technical distinction between connection assets and interconnection assets hinges on whether the assets in question form a loop. Generally speaking, 'looped assets' are interconnection assets.[268]

B.295 However, this can create inefficiencies. An example of how this could occur is Waipa Networks' construction of a line between the Te Awamutu and Hangatiki substations. This created a loop with assets that had previously been classified as connection assets and therefore were previously subject to connection charges.

B.296 The new line and associated works (switchgear) were constructed under a customer investment contract (CIC) and costs are recovered under that CIC (not the TPM). However, when the new line was commissioned, the substations and related assets became part of a loop. Hence, it appears that some of Transpower's assets (for example, the Karapiro–Te Awamutu line) became interconnection assets (as defined in the TPM), even though:

(a) the new line that completed the loop is owned and operated by a grid provider other than Transpower (that is, by Waipa Networks) and

(b) the new line is not a grid asset in respect of which the TPM allocates charges.

B.297 If it were not for this additional component, under a TPM that reflected the proposed guidelines, the cost of investments like these might be recovered through the benefit-based charge rather than through the connection charge.

B.298 Waipa Networks submitted that the outcome without this additional component was the correct one, so the additional component is not needed. PwC for 14 EDBs considered that there is a problem, but that Transpower should develop a workable solution, and that the additional component should not be introduced unless it is very clear that it is needed.[269]

B.299 Our view is that the reclassification of investments like these as interconnection assets does not promote efficient investment to the extent that the costs of connection and interconnection assets are recovered differently. For example, if the charges that a customer faces when assets are classified as interconnection assets are less than they would face when the assets were classified as connection assets, it provides an incentive for the customer to have them classified as interconnection assets.

B.300 Further, there are unnecessary transaction costs if the investment is subject to the benefit-based charge when in substance it provides connection services.

B.301 These inefficiencies would be addressed if assets that principally provide connection services (after they are connected by a new line) continued to be categorised as connection assets.

---

267 The definition of grid assets identifies the specific assets for which charges in the TPM must be calculated.

268 The exception to this rule is that: small local loops are classified as connection -, not interconnection- assets.

269 Submissions on the second issues paper.

Additional Component C: charges for connection assets

Proposal

Clause 57, proposed TPM guidelines (appendix A)

Discussion

B.302 Currently, Transpower includes all connection investments in a pool, and calculates the charge for each connection asset based on the average depreciation of the pool.[270] The proposed guidelines largely retain the wording of the existing guidelines for connection investments, which would allow Transpower to continue the existing treatment.

B.303 The proposed guidelines may create boundary issues, given that they provide for two distinct classes of transmission investments (connection and interconnection investments), each with a distinct method for determining charges. This could create inefficient incentives for transmission customers to prefer connection investments over investments in the interconnected grid or vice versa. This could come about, for example, because the asset return rate component of the connection asset charge involves valuing connection assets on an average historic cost (AHC) basis, which is different from the approach proposed for valuing assets for the benefit-based charge.[271] Depending on which category was more beneficial for it, a customer could then lobby for a given investment to be configured as either:

(a) a connection investment, subject to the connection charge; or

(b) an investment in the interconnected grid, subject to the benefit-based charge.

B.304 This potential boundary problem would be addressed if the method for determining connection charges in relation to each new connection asset was substantially the same as the corresponding method for benefit-based charges.

B.305 In their submissions on the second issues paper, Fonterra, Meridian and Winstone Pulp supported this proposal. PwC for 14 EDBs was opposed because it considered that it would increase cost and complexity, as well as likely making charges more variable over time. Our view is that if this is the case, the additional component would not be introduced because it would not better meet our statutory objective.

270 This is discussed further on page 76 of the second issues paper.

271 This is discussed in paragraph 7.148(b) of the second issues paper.

Additional component D: transitional peak charge

Proposal

Clauses 58 - 61, proposed TPM guidelines (appendix A)

Discussion

B.306 We have included a transitional peak charge in the proposed guidelines, and have omitted the long-run marginal cost (LRMC) charge that was included in the 2016 TPM proposal. Although that charge was called an LRMC charge, the 2016 draft guidelines allowed wide discretion in the design of the charge.[272] The change in name to peak charge is designed to clarify what the charge is intended to do and how the charge may be designed. As with the corresponding component in the 2016 TPM proposal, this additional component allows for, but is not restricted to, a charge that is initially based on the LRMC of transmission.

B.307 Whether to include a peak charge in the proposed guidelines and, if so, the form of the peak charge is a key design choice in our proposal. The broad context for this decision is that, as is discussed above and in appendix E, we expect that nodal prices, the transmission charges provided for in the proposed guidelines and the Commerce Commission regulatory regime would provide incentives for efficient use of and investment in the grid. So a peak transmission charge may not be necessary.

B.308 We have considered three broad options, which involve including the peak charge as a core component of the proposal, as an additional component or not including it at all.

B.309 Transpower prepared a report on peak pricing for transmission at our request.[273] We have considered this report in forming our proposal on the peak charge. We have discussed our response to the Transpower report and our views about a peak charge in appendix E.

B.310 Our current preferred option is to include it as an additional component, but to make it transitional only. We have included it as an additional component because we think it may have benefits in some circumstances, but these are uncertain, and may or may not be outweighed by potential costs of including the charge.

B.311 In summary, we have included a transitional peak charge because we propose to remove explicit (RCPD) peak pricing from transmission pricing, and because of some other transitional issues. Removing the RCPD charge is a significant change and raises the possibility that there could be a large increase in demand for energy during periods that currently are or could be RCPD peaks.

B.312 In particular, as Transpower noted in its report on peak pricing, the current RCPD charge provides a price incentive on distributors to use load control to limit their offtake from the grid during regional peaks. Most distributors do not currently face wholesale energy prices so it is uncertain how they would react when the RCPD signal is removed. Removal of the RCPD charge might mean that distributors stop (or significantly reduce) their management of demand at times of regional coincident peak demand.

B.313 Where there is no consequent congestion, this would be desirable, since it means that users can access additional energy efficiently.

---

272 The major constraint on it was that it had to complement the effect of nodal prices in promoting efficient investment and efficient use of the grid.

273 *The role of peak pricing for transmission,* available at https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/role-peak-pricing-transmission

B.314 However, where there is congestion, nodal prices will rise. This will incentivise users to reduce their least-valued energy use. This incentive is likely to become increasingly effective over time, both as a result of the introduction of real-time pricing and as emerging technology and new business models enable energy use to become increasingly price-responsive. As noted in a report appended to Transpower's peak pricing paper, technology can play an important role in enhancing demand response and the ways in which users are able to respond to a change in electricity tariffs may be expected to change over time. [274]

B.315 In the short to medium term however, there is a risk that at some nodes during system peaks demand and supply might not be sufficiently responsive to nodal prices and some other form of rationing might be required. In this circumstance, price rationing is likely to be preferable to quantity rationing since the former tends to target the lowest value energy use.

B.316 As a result, we propose that Transpower could introduce a temporary peak charge, targeted to those areas where it is needed to influence grid use. Since this would be a transmission charge, it can mitigate the concern that distributors might respond to removal of the RCPD charge by abruptly abandoning or reducing administrative demand control.

B.317 Having a transitional peak charge would also allow time for the emergence and uptake of demand control technologies and new business models. It would allow parties such as aggregators time to respond to the eventual removal of the transitional peak charge.

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

B.318 We have a number of additional choices to make if the guidelines do include a transitional peak charge.

B.319 First, there is the question of how widely the transitional peak charge would apply. We are proposing that the charge be targeted in its application, that is, it is only to be levied in those geographic areas or on those circuits which Transpower considers could be congested in the absence of such a charge. Our current thinking is that there is no need for a charge in uncongested parts of the grid, and it is undesirable to suppress demand unnecessarily in such locations. Furthermore, since the charge would complement nodal prices, we would expect Transpower only to apply the charge where it considers that nodal prices will not be able on their own to limit demand for transmission use to capacity and that an additional transmission charge would help in controlling demand.

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

B.320 Second, we have a choice to make about when the charge would be applied. Our current thinking is that if the charge is introduced, it would be introduced at the start of the new TPM and would then be progressively phased out. This reflects our view that the peak charge is to limit risks associated with the initial removal of the RCPD charge and that the need for a peak charge will reduce over time as the scope for demand to respond to nodal prices grows (due to RTP and the increasing emergence and uptake of demand control technology and new business models). Our concern is that a permanent peak charge could cause ongoing distortion to the efficient operation of nodal prices.

---

274 Frontier Economics, Peak-use charging; A review of price elasticity of demand, October 2018

B.321 We are proposing that, after an initial year of operation, the peak charge be phased out gradually so as to avoid any problems that might result from a sudden reduction in the charge. We are considering two main options for the duration of the phase-out period: 5 years and 10 years. Our current thinking is that Transpower would include in the TPM a plan for phasing out the charge so that it is phased out within 5 years of the TPM entering into effect, after an initial period of operation. The plan would specify the maximum peak charge that Transpower could charge in any year, possibly as a percentage of the initial peak charge.

B.322 We are envisaging that Transpower would monitor developments in real time and adjust the charge to take account of developments as they actually occur. Transpower could for example:

(a) determine a maximum level for the peak charge in selected areas (which reduces gradually to zero over the phase-out period)

(b) set the charge at some level below the maximum for each area, so it has scope to increase the charge temporarily up to the maximum peak charge level if circumstances warranted it, subject to the overall general trend of phasing out the charge.

B.323 Transpower could apply to the Authority to alter any of the parameters of a peak charge. For example, it could seek to extend the phase-out period beyond 5 years or increase the maximum level of the peak charge, if it could show there were net benefits in doing so.

B.324 We have also provided for Transpower to apply to the Authority, as part of an operational review, to introduce (or re-introduce) a peak charge at a later date if that would better meet the Authority's statutory objective. This is to ensure that Transpower does have sufficient flexibility to respond to developments as they occur, while ensuring designated transmission customers have the chance to have input into any such decision.

B.325 We have not included a permanent peak charge in our proposal as a core component or an additional component. We are well aware that some submitters consider that including such a charge in the TPM would better achieve our statutory objective. Because of this, we did carefully consider the possibility of including one, but decided not to propose one. We have outlined our thinking for adopting this approach in appendix E.

Q46. Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?

B.326 If the new TPM includes a transitional peak charge, the amount of revenue recovered through the residual charge would automatically fall to make up for the additional revenue generated by the peak charge.

Additional Component E: Including additional pre-2019 investments in the benefit-based charge

Proposal

Clauses 62 and 63, proposed TPM guidelines (appendix A)

Discussion

B.327 We have proposed above that the benefit-based charge would recover the covered cost of each asset in a benefit-based investment.

B.328 Without this additional component, benefit-based investments would be defined to include all future investments and a small number of high-value pre-2019 investments.

B.329 The proposed guidelines require Transpower to include in the TPM a method for extending the benefit-based charge to further pre-2019 assets if that would better achieve our statutory objective.

B.330 Several submissions on the second issues paper[275] and supplementary consultation paper[276] have suggested that the benefit-based charge should be extended to a wider range of pre-2019 assets. Their reasons included:

(a) It involves recovering costs on a beneficiaries-pay basis, and would be cost reflective and service based, rather than through the residual charge.[277]

(b) It is consistent with the finding in the sunk cost working paper,[278] that infra-marginal decisions are as important for efficiency as marginal decisions.[279, 280] 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 could incentivise more efficient ownership decisions. (Ownership

---

275 They included Contact Energy, E-Type Engineering, Grey Power Southland, Market South, McIntyre Dick and Partners, Otago Chamber of Commerce, Otago Southland Employers' Association, Pacific Aluminium, Preston Russell Law, Sarah Dowie, Southland Chamber of Commerce, Southland Manufacturers Trust, Stabicraft Marine, Todd Barclay Transpower and Unison.

276 Fonterra, Contact Energy, Oji Fibre Solutions, Pacific Aluminium, New Zealand Aluminium Smelter, Transpower, Top Energy, Ngawha Generation, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central. The following suggested that the charge should recover as much of Transpower's recoverable revenue as possible: Awarua Synergy, Dongwha, EIS, E-Type Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland, Otago Southland Employers' Association, Port Otago, Queenstown Lakes District Council, Dunedin City Council, Clutha District Council, Business NZ, Canterbury Employers' Chamber of Commerce, Business Central, ENA, Alpine Energy, Aurora Energy, Buller Electricity, Counties Power, Eastland Network, Electra, EA Networks, Horizon Energy Distribution, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, Powerco, PowerNet, Scan Power, The Lines Company, Top Energy, Unison, Vector, Waipa Networks, WEL Networks, Wellington Electricity Lines, Westpower

277 Submission on the supplementary consultation paper by Pacific Aluminium and Transpower

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

279 NZAS' submission on the second issues paper.

280 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.

decisions are infra-marginal decisions, since they involve consideration of more than just the marginal cost of using the assets).[281]

(c) It could reduce potential distortions to efficient location of generation and load resulting from applying the benefit-based charge to only a subset of pre-2019 assets.[282] For example, applying the benefit-based charge to the Wairakei Ring but not to nearby transmission assets may inefficiently discourage a new generation plant from connecting to the Wairakei Ring.[283]

(d) It would reduce distortions from an excessive residual charge. Applying the benefit-based charge to more pre-2019 assets would result in a greater amount of revenue being collected through the benefit-based charge and less revenue being collected through the residual charge. This would lower the rate of the residual charge.

(e) It would reduce wealth transfers, because under our proposal generators would pay the benefit-based charge but not the residual charge.[284] Some submitters have suggested the wealth transfers under the proposal could affect its durability and thus its efficiency.

B.331 Taken together, these reasons suggest there would be merit in considering whether to apply the benefit-based charge to more pre-2019 assets.

B.332 On the other hand, several submitters on the supplementary consultation paper raised concerns on the proposal, including:

(a) it may be difficult to establish meaningful charges[285]

(b) it would be a wealth transfer without efficiency effects[286]

(c) it would compromise static efficiency, and would be unrelated to the rationale of improving dynamic efficiency.[287]

B.333 Transpower would need to take these sorts of considerations into account in determining whether to extend the benefit-based charge to these investments. Transpower would also need to consider the costs of calculating benefits and identifying beneficiaries when considering the coverage of the charge.

B.334 The cost of extending the benefit-based charge to more pre-2019 investments would depend on the method used for allocating the charge. (If Transpower proposes to include this additional component in the TPM, it must also include such a method). As is discussed

281 This assumes that both Transpower and the potential owner will have normal commercial incentives to buy and sell the asset at its true (regulated) economic value; that is at the net present value of net revenues it is expected to generate. We note there may also be other incentives resulting from the Commerce Commission's IPP and DPP regime that may affect decisions to transfer assets.

282 Transpower's submission on the second issues paper, page 25.

283 We acknowledge that this would only reduce, and not eliminate, this potential locational distortion. This issue is discussed more fully earlier in this paper.

284 Unlike the residual charge, the benefit-based charge may not be fully passed through prices and be borne by energy consumers. This is because different generators will face different rates of benefit-based charge. In any case, some pass-through of the benefit-based charge is desirable because it reflects the infra-marginal cost of the associated transmission investments.

285 NERA for Meridian

286 Trustpower, Bushnell/Wolak for Trustpower, Professor Yarrow for Trustpower, CEC for Trustpower, Houston Kemp for Trustpower, EA Networks, Vector, Entrust

287 Covec, Counties Power, Counties Power Consumer Trust, ENA, Entrust, Northern Federated Farmers, Northpower, Top Energy, Trustpower, Vector

earlier, there are fewer benefits and potentially greater costs in applying the benefit-based charge to pre-2019 investments relative to post-2019 investments, and less benefit to accurately allocating the charges, principally because the charges can have no impact on whether the investment is undertaken or not. This means that it is appropriate to adopt a simple method for determining the allocation of benefits from pre-2019 investments. Adopting a simple method would also facilitate applying the benefit-based charge to more pre-2019 assets.[288] In addition, the proposals under *General matters* above require Transpower to balance the benefits of accuracy against various practical issues. This should ensure that the costs of broadening the coverage would be effectively managed.

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

B.335 Transpower has indicated that it may not have information on the pre-2019 cost of its older transmission investments. The proposals discussed under the heading *General matters* above make clear that if this is the case Transpower would need to take such practical considerations into account when it establishes the method for determining the charges.

B.336 It may be appropriate for the method for allocating charges for pre-2019 investments to be different from the simple method for allocating low-value investments (despite the criteria being the same). This is in part because the main benefit of a low-value investment is likely to be relatively concentrated geographically, but that is typically not true of larger pre-2019 investments.

B.337 Since Transpower could extend the benefit-based charges to potentially all pre-2019 assets, both the magnitude and the incidence of price increases may differ from that modelled in this paper. 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.

B.338 For any of the investments that Transpower includes under this additional component, it is possible that the future benefits that transmission customers collectively get from that investment are less than its covered cost. If so, the proposed guidelines provide for the initial benefit-based charge to be capped at the estimated net present value of positive net private benefit that the customers are estimated to receive from the investment. This proposal takes account of the fact that, unlike for an efficient new investment, the benefits it is expected to yield may be less than its covered cost at the time the benefit-based charge is first applied to the investment. This could occur, for example, because the benefits that the investment is now expected to provide are quite different from the benefits that were expected when the investment was made.

B.339 If this additional component is included in the TPM, the proposed guidelines provide that the TPM may include a transition. For example, this could be a provision that has a similar effect to the cap discussed under the heading *Cap on transmission charges* above. The reason for providing for this transition is the same as the reason for providing the cap discussed under that heading above.

B.340 The Authority has chosen not to be more specific about the nature of the transition, because the design of the transition is best undertaken once the decision has been made about which additional pre-2019 assets will be subject to the benefit-based charge.

288 Transpower's submission on the second issues paper proposed that a simple method be used for calculating the benefit-based charge for pre-2019 investments.

Additional component F: charging for opex

Proposal

Clause 64, proposed TPM guidelines (appendix A)

Discussion

B.341 Opex for connection investments is currently spread across connection customers using broad cost allocation rules. As is discussed in paragraph B.72 above the main (mandatory) part of the proposed guidelines would allow Transpower to use broad cost allocation rules to allocate opex costs for benefit-based investments.

B.342 This additional component instead proposes to attribute opex to the asset it was spent on (without use of broad allocation rules or similar). For example, if a building that is part of a benefit-based investment is painted, the cost of painting it would be included in the covered cost of the investment incorporating the building, and recovered from the designated transmission customers paying benefit-based charges in relation to that investment. Charging for opex on this basis will result in charges better reflecting actual costs. This will create an incentive for customers to take the costs actually incurred into account when they consider whether to support maintenance, replacement and upgrading of investments.

B.343 Most submissions on the supplementary consultation paper considered this proposal reasonable, provided it can be carried out cost effectively.[289] However, some submitters were concerned that the allocation would also allocate common costs,[290] which would not be appropriate. Since Transpower would need to satisfy itself that this additional component would better meet our statutory objective before it proposed this additional component, Transpower would need to reassure itself about these points.

B.344 One benefit of retaining broad cost allocation rules is that this is a relatively low-cost method of determining charges. However, the disadvantage of broad cost allocation rules is that they mask the differences in the actual costs of operating and maintaining different assets. This proposal would make connection charges and benefit-based charges better reflect the costs of the relevant investments, and therefore lead transmission customers to support more efficient investment and operational decisions over time. Determining charges in this manner would make the costs more transparent, giving customers the ability to test with Transpower whether they are reasonable. This would help contribute to lower overall costs over time.

B.345 Some submitters have raised concerns that Transpower's customers do not have the ability to scrutinise Transpower's maintenance practices.[291] The Authority considers that making Transpower's opex more transparent will give at least its larger customers additional ability to scrutinise these costs and require Transpower to justify why they are reasonable. Further, distributors have similar businesses to Transpower (albeit operating lower voltage

---

289 For example, Venture Southland, Awarua Synergy, Dongwha, EIS, E-Type Engineering, HW Richardson Group, Southland Chamber of Commerce, South Port, Sarah Dowie MP, Southland District Council, Southland Manufacturers Trust, Southland Mayoral Forum, Todd Barclay MP, Invercargill City Council, Gore District Council, Grey Power Southland, Export Southland, Otago Southland Employers' Association, Port Otago, Queenstown Lakes District Council, Dunedin City Council, Clutha District Council, University of Otago, PwC, Alpine Energy, Aurora Energy, EA Networks, Eastland Network, Electra, Mainpower, Marlborough Lines, Nelson Electricity, Network Tasman, Northpower, The Lines Company, Top Energy, Waipa Networks, Westpower.

290 For example, Meridian Energy, NERA for Meridian, New Zealand Aluminium Smelter, Pacific Aluminium.

291 For example, the submission of CEC for Trustpower on the second issues paper

assets) so they are in a relatively strong position to scrutinise Transpower's operating and maintenance practices.

B.346 There is a risk that attributing opex to the assets it is spent on could lead to some customer resistance to maintenance that would extend the life of an asset. However, this seems much less likely than under the current TPM (unless deferring maintenance is in fact optimal). This is because the customers whose charges would incorporate the opex would also have to pay the cost of the early replacement of the asset under the benefit-based charge and potentially the connection charge.

B.347 On the other hand, basing maintenance charges on costs incurred in respect of an individual asset or investment may lead to a concern that parties may be incentivised to seek refurbishments or replacements earlier than is efficient to limit the maintenance charges they would face. Under the section of our proposal relating to the benefit-based charge, we propose that:

(a) following replacement or refurbishment, Transpower would continue to charge the cost of the old investment until that investment is fully depreciated

(b) charges for the capital cost of an asset cease once it is fully depreciated so that the full capital costs in respect of the asset have been recovered.

B.348 This should provide an efficient incentive for Transpower's customers to oppose unnecessary replacements or refurbishments.

B.349 Basing maintenance charges on costs incurred in respect of individual assets or investments may also lead to more efficient incentives around ownership of assets. Under the current rules, there may be an inefficient incentive for transmission customers to purchase feeder lines that are in good condition from Transpower, leaving the poor-condition feeder lines in the common pool. The proposal would reduce this incentive.

B.350 We note that, during the course of consultation on the 2016 proposal, some parties submitted that maintenance costs are negatively correlated to DHC asset values, because maintenance costs increase over time as an asset depreciates in value. This would suggest that DHC or an asset's value would not be suitable allocators for maintenance costs.

B.351 We have included this proposal as an additional component because it is a relatively low-priority issue. This is because maintenance costs are generally a small component of the charges for an asset.

Additional component G: kvar charge

Proposal

Clause 65, proposed TPM guidelines (appendix A)

Discussion

B.352 The Authority currently considers that there would be no immediate, material benefit in introducing a kvar charge. However, it is desirable to provide for the introduction of a kvar charge in case there are net benefits from having it in the future. This would give Transpower the option of proposing a kvar charge at some point in the future, if power factors deteriorate.

B.353 A kvar charge may provide a more efficient means of maintaining power factors than enforcing the power factor requirements in the Connection Code.[292] Like nodal prices, the kvar charge is intended to be complementary to the benefit-based charge that would be imposed if an investment in equipment to correct a power factor is required. A kvar charge would be similar in intent to the nodal transport charge inherent in nodal prices. That is, just as nodal prices reflect the cost of congestion that users impose on others by using the grid, the kvar charge is intended to be a charge levied on those that cause the deterioration in the power factor to reflect the cost that deterioration imposes on other grid users.[293] This cost arises at times when the relevant circuits are congested. As a result it would be desirable to target the charge on these circuits at these times.

B.354 At this stage, our view is that, if Transpower decides to propose a kvar charge, it is best placed to determine the details of the charge.

B.355 Although the TPM can specify how a kvar charge is to be calculated and the circumstances in which it is to apply, it does not need to be specific about what the level of kvar charge is or in which particular regions it will apply. In other words, Transpower can determine the circumstances in which the kvar charge will apply in the TPM, and then determine in real time whether those circumstances apply.

B.356 Transpower, distributors and direct consumers could choose to respond to the kvar charge by installing reactive support equipment, and distributors could also apply a kvar charge to their customers, which some have done. In the case of Transpower, the benefit-based charge would apply to such investments, with the beneficiaries being those who would avoid the kvar charge as a consequence.

B.357 The decommissioning of the Otahuhu B and Southdown power stations may have increased the need for upper North Island dynamic reactive investment. However, if such equipment were necessary, the benefit-based charge would mean that the cost of it would be recovered from those who benefit by not having to pay the kvar charge that would otherwise be imposed.

B.358 Some submitters have expressed the view that improving appliance standards would be likely to provide a more efficient response than kvar price signals. The Authority does not determine appliance standards. However, it can influence such standards through its

[292] We are now intending to pursue separately the related change to the Code to specify a minimum power factor of 0.95.

[293] However, it is unlikely that a kvar charge will be applied in real time in the near future. As a consequence, some approximation, such as a LRMC charge focused on those users whose actions lead to the deterioration in power factor, may be appropriate.

policies, such as the introduction of a kvar charge, which would provide incentives for parties subject to the charge to influence the standards. In any case, except for large consumers, it is likely to be more efficient to deal with reactive load through investment at the transmission or distribution level, than at the end-consumer level.

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