TRANSPOWER

TPM Proposal Reasons Paper

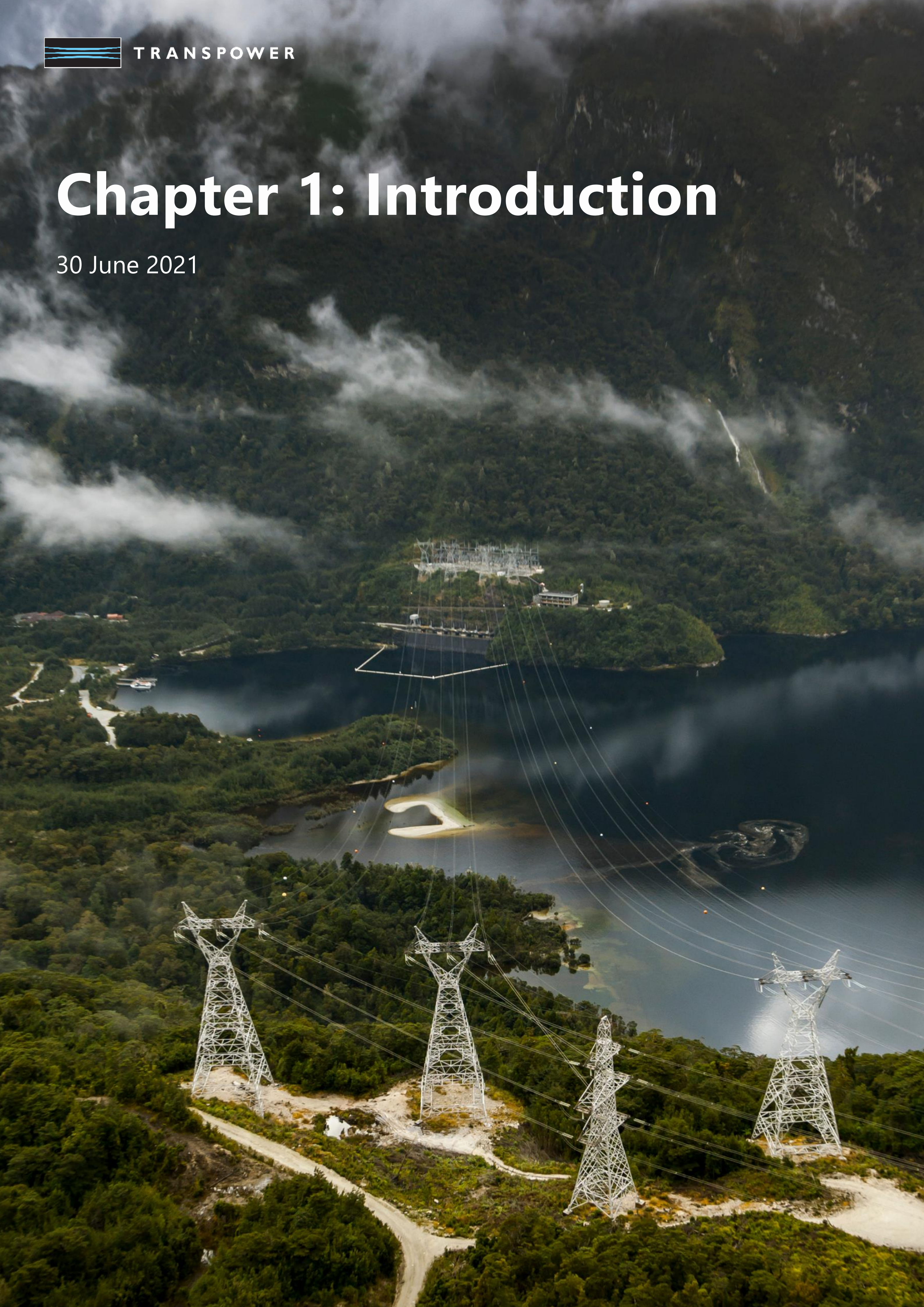
30 June 2021

Contents

TRANSPOWER

Chapter 1: Introduction

30 June 2021



Contents: Chapter 1

1 Introduction

1. The purpose of this paper is to summarise and explain the reasons for key design decisions Transpower has made as it developed its proposed new transmission pricing methodology (**TPM**).

1.1 Context

2. The Electricity Authority (**Authority**) released its final decision on its transmission pricing review and published new TPM Guidelines (**Guidelines**) on 10 June 2020. [1]

3. The Authority gave Transpower until 30 June 2021 to develop and propose a new TPM that is consistent with the Guidelines and the other requirements under Part 12 of the Electricity Industry Participation Code 2010 (the **Code**).[2]

4. Following receipt of our proposal to the Authority, the Authority follows a process set in Part 12 of the Code before deciding whether to approve any change to the TPM and when it will take effect.[3]

1.2 The role of the TPM

5. The Commerce Commission (**Commission**) determines how much revenue Transpower, as the owner and operator of the National Grid owner, can recover from its customers according to its regulation of Transpower under Part 4 of the Commerce Act. The TPM determines how that amount of allowable revenue is recovered from (or allocated to) each of Transpower's customers in each pricing year.

6. The Commission is also responsible for regulating investment in the grid, including through the Transpower Capex IM (**Capex IM**). The Capex IM comprises the rules and processes for approving capital expenditure (Transpower's applications and the Commission's assessments), including the Investment Test. Once Transpower's capital expenditure

---

[1] Authority, Transmission pricing methodology: 2020 Guidelines and process for development of a proposed TPM: Decision, 10 June 2020 (Reference document #3 2020 Decision and Reference document #4 Guidelines).

[2] Electricity Industry Participation Code (the **Code**) - Part 12 - Transport

[3] The process the Authority will apply following receipt of this proposal from Transpower is explained in Chapter 2 (Framework for our proposal)

proposal has been approved by the Commission, whether as major capex or base capex, that spend (and an allowable return on investment) may be recovered through the TPM.

7. The Commission has noted:

> The new TPM guidelines and the new TPM Transpower develops under them will not affect the regulatory approval process for assessing the [Major Capex Proposal] under the Capex IM or the amount Transpower can recover in transmission charges for the investment. [4]

1.3 The TPM's approach to transmission pricing is changing

8. The Authority's decision to approve and publish new TPM Guidelines requires material change to the way in which Transpower's allowable revenue will be allocated to designated transmission customers. The following diagram provides a high-level overview of the change:

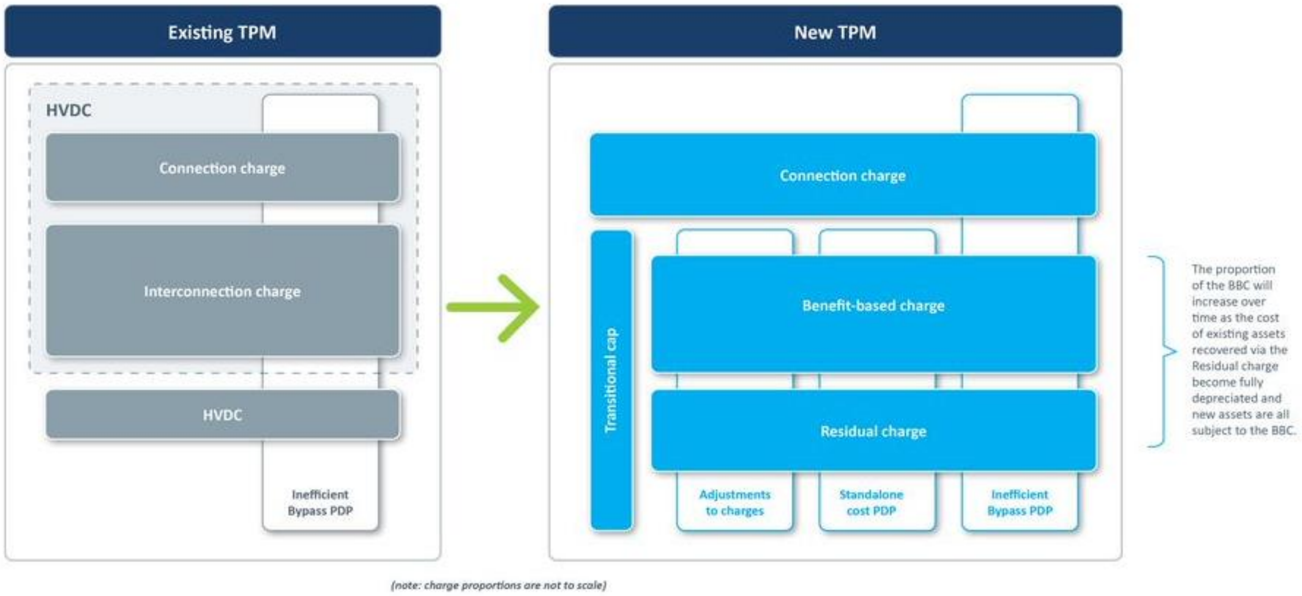


Figure 1 Overview of the change from the current TPM, to the new TPM under the 2020 Guidelines

1.4 Transpower's TPM Proposal

9. An overview of the documents, supporting materials and assurance reports comprising Transpower's TPM proposal is shown in Figure 2 below.

[4] Commerce Commission Decision and reasons on Transpower's Bombay Otahuhu Regional MCP, 19 March 2021, paragraph 27.

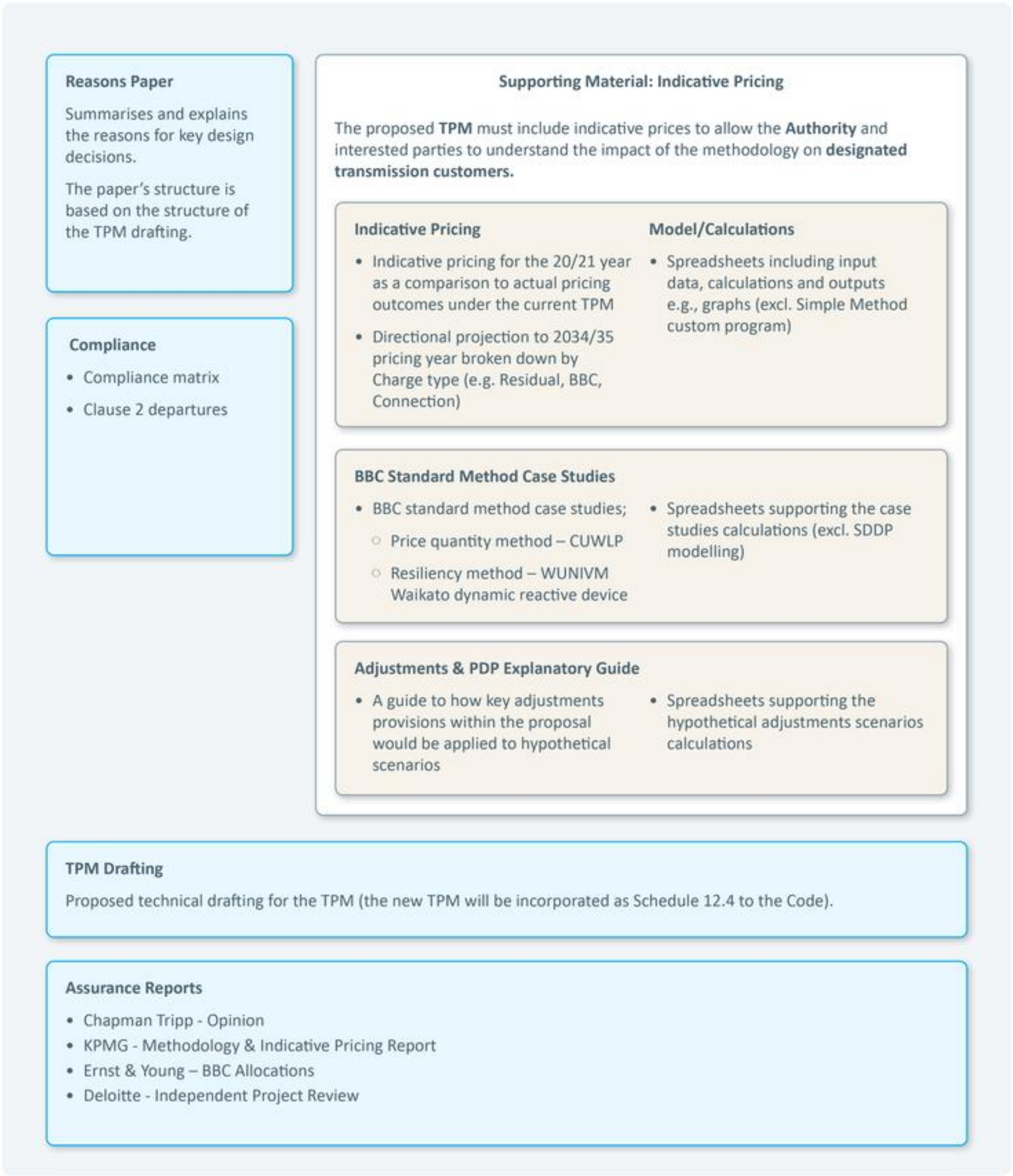


Figure 2 Overview of the proposal

2 Reference documents

Doc. #	Date	Author	Reference Document
1.	23 July 2019	Authority	TPM 2019 Issues paper: 2019 Issues paper
2.	11 Feb 2020	Authority	2019 Issues paper, Supplementary consultation
3.	10 June 2020	Authority	TPM 2020 Guidelines and process for development of a proposed TPM: Decision 2020 Decision
4.	10 June 2020	Authority	2020 TPM Guidelines: Guidelines
5.	10 June 2020	Authority	Letter from EA: Development of a proposed new TPM
6.	31 Jul 2020	Transpower	Letter to EA: TPM Project Timeline
7.	11 Aug 2020	Authority	Letter from EA: TPM Project Timeline
8.	14 Aug 2020	Transpower	Letter to EA: Checkpoint 1 submission BBC
9.	14 Aug 2020	Transpower	Checkpoint 1 submission: BBC
10.	17 Aug 2020	Transpower	Design Principles
11.	24 Aug 2020	Transpower	Connection charges consultation paper
12.	31 Aug 2020	Authority	Letter from EA: Checkpoint 1 submission BBC
13.	22 Sept 2020	Transpower	Letter to EA: Checkpoint 1 and 2 update
14.	29 Sept 2020	Transpower	Design Principles Summary and Response
15.	1 Oct 2020	Transpower	Letter to EA: Checkpoint 1 resubmission BBC
16.	1 Oct 2020	Transpower	Checkpoint 1 resubmission: BBC
17.	1 Oct 2020	Authority	Letter from EA: Checkpoint 1 and 2 phasing
18.	6 Oct 2020	Transpower	TCC workshop #1: transcript
19.	6 Oct 2020	Transpower	TCC workshop #2: transcript
20.	9 Oct 2020	Authority	Letter from EA: Checkpoint 1 resubmission BBC
21.	20 Oct 2020	Transpower	Connection Charges consultation: Summary and Response
22.	28 Oct 2020	Transpower	Prudent Discount Policy consultation paper
23.	28 Oct 2020	Transpower	First Mover Disadvantage consultation paper
24.	3 Nov 2020	Transpower	Letter to EA: TPM project timeline and Options consultation
25.	9 Nov 2020	Transpower	TPM Options consultation paper: Part A Overview
26.	9 Nov 2020	Transpower	TPM Options consultation paper: Part B BBC
27.	9 Nov 2020	Transpower	TPM Options consultation paper: Part C Adjustments
28.	11 Nov 2020	Authority	Letter from EA: TPM project timeline and Options consultation
29.	16 Nov 2020	Transpower	Letter to EA: Checkpoint 2 submission Price Cap, Residual and Connection Charge
30.	16 Nov 2020	Transpower	Checkpoint 2 submission: Connection Charge
31.	16 Nov 2020	Transpower	Checkpoint 2 submission: Residual Charge and Transitional Cap
32.	23 Nov 2020	Transpower	TCC engagement: Summary and Response
33.	23 Nov 2020	Transpower	Letter to EA: Checkpoint 1 Submission TCC
34.	23 Nov 2020	Transpower	Checkpoint 1 submission: TCC
35.	7 Dec 2020	Authority	Letter from EA: Checkpoint 2A submission
36.	14 Dec 2020	Authority	Letter from EA: Checkpoint 1 submission TCC
37.	21 Dec 2020	Transpower	First Mover Disadvantage consultation: Summary and Response
38.	21 Dec 2020	Transpower	Prudent Discount Policy consultation: Summary and Response
39.	18 Jan 2021	Transpower	Letter to EA: Checkpoint 1 resubmission: TCC
40.	18 Jan 2021	Transpower	Checkpoint 1 resubmission: TCC
41.	22 Jan 2021	Transpower	Letter to EA: Checkpoint 2 resubmission Residual Charge and Transitional Cap

Doc. #	Date	Author	Reference Document
42.	22 Jan 2021	Transpower	Checkpoint 2 resubmission: Residual Charge and Transitional Cap
43.	4 Feb 2021	Authority	Letter from EA: Checkpoint 1 resubmission TCC
44.	4 Feb 2021	Authority	Letter from EA: Checkpoint 2A resubmission Residual Charge and Transitional Cap
45.	1 Mar 2021	Transpower	Letter to EA: Project Timeline and Options Consultation
46.	1 Mar 2021	Transpower	Letter to EA: Checkpoint 2B submission
47.	1 Mar 2021	Transpower	Checkpoint 2B submission: Adjustments
48.	1 Mar 2021	Transpower	Checkpoint 2B submission: BBC allocation
49.	1 Mar 2021	Transpower	Checkpoint 2B submission: BBC Covered Cost
50.	1 Mar 2021	Transpower	Checkpoint 2B submission: First Mover Disadvantage
51.	1 Mar 2021	Transpower	Checkpoint 2B submission: Prudent Discount Policy
52.	1 Mar 2021	Transpower	Checkpoint 2B submission: preliminary TPM drafting
53.	5 Mar 2021	Transpower	TPM Options consultation: Summary and Response
54.	18 Mar 2021	Authority	Letter from EA: Batteries and the Residual Charge
55.	22 Mar 2021	Transpower	Batteries and the Residual Charge consultation paper
56.	22 Mar 2021	Authority	Letter from EA: Checkpoint 2B submission
57.	22 Mar 2021	Authority	Letter from EA: TPM Project Timeline and Options consultation
58.	3 May 2021	Transpower	Letter to EA: Checkpoint 2B Resubmission and Batteries Submission
59.	3 May 2021	Transpower	Checkpoint 2B resubmission: Adjustments
60.	3 May 2021	Transpower	Checkpoint 2B resubmission: BBC Allocation
61.	3 May 2021	Transpower	Checkpoint 2B resubmission: BBC Covered Cost
62.	3 May 2021	Transpower	Checkpoint 2B resubmission: First Mover Disadvantage
63.	3 May 2021	Transpower	Checkpoint 2B resubmission: Prudent Discount Policy
64.	3 May 2021	Transpower	Checkpoint 2B resubmission: preliminary TPM drafting
65.	3 May 2021	Transpower	Checkpoint 2C submission: Batteries and the Residual Charge
66.	12 May 2021	Transpower	Batteries and the Residual Charge: Summary and Response
67.	24 May 2021	Authority	Letter from EA: Checkpoint 2B resubmission
68.	24 May 2021	Authority	Letter from EA: Checkpoint 2B resubmission Appendix A-D
69.	24 May 2021	Authority	Letter from EA: Checkpoint 2B resubmission Appendix E comments on preliminary TPM drafting
70.	24 May 2021	Authority	Letter from EA: Checkpoint 2C submission Batteries and the Residual Charge
71.	Consolidated version 29 Jan 2020	Commerce Commission	Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination) (Transpower Capex IM)
72.	Consolidated version 29 Jan 2020	Commerce Commission	Transpower Input Methodologies Determination 2010 (Transpower IMs)
73.	14 Nov 2019	Commerce Commission	Transpower Individual Price-Quality Path Determination 2020 [2019] NZCC 19 (Transpower IPP)

3 Glossary

The table below presents acronyms and terms to which we refer in this paper. In addition, the proposed TPM drafting with this paper defines terms and acronyms on which the TPM relies.

Term	Meaning
AMDR	Anytime Maximum Demand Residual, (a Gross measure) used for allocating the Residual Charge
Authority	The Electricity Authority
AC	Alternating current
BBC	Benefit-based charge, a charge to recover the covered cost of a BBI
BBI	Benefit-based investment
Capex	Capital expenditure, as defined in Transpower IMs
CNI	Central North Island
Code	Electricity Industry Participation Code 2010
Commission	The Commerce Commission
Consumer surplus	The difference between the maximum that consumers would be willing to pay and what they actually paid for their consumption
Contingency	An unplanned event in the power system, including loss of a transmission asset
CNI	Central North Island
Customer	A customer of Transpower connected to the grid (aka designated transmission customer)
CUWLP	Clutha-Upper Waitaki lines project, a major transmission investment started in 2020
Dynamic efficiency benefits	Net benefits to society from transmission investment enabling cheaper generation to be built
E&D	Enhancement and development investments, less than $20m driven by demand increases or generation changes
EDGS	Electricity demand and generation Scenarios (from MBIE)
EOC	Exceptional operating circumstance, a situation where transmission charge allocation data can be adjusted to remove the effect of exceptional operation
EV account	Economic value account, a wash-up mechanism under the IPP
FMD	First mover disadvantage
FTR	Financial transmission rights, a mechanism to manage locational price risk
GEIP	Good electricity industry practice
GRS	Grid reliability standards, refer to Schedule 12.2 of the Code
HAMD	Historical anytime maximum demand (same as AMDR)
HB	Hawkes Bay
HC	Historic cost
HVDC link	High voltage direct current inter-island link, the transmission link between the North and South islands
IBPD	Inefficient bypass prudent discount
Investment Test	The investment approval test under the Capex IM
IPP	Individual price-quality path economic regulation which applies to Transpower

Term	Meaning
kVAr	KiloVolt Ampere reactive (reactive power)
kW	KiloWatt (power)
kWh	KiloWatt hour (energy)
Lagged adjustments	Adjustments to the residual charge allocations by reference to a lagged gross energy scalar
LNI	Lower North Island
LSI	Lower South Island
MAR	Maximum Allowable Revenue, set by the Commerce Commission (called Recoverable Revenue under the TPM).
MBIE	Ministry for Business, Innovation & Employment
MCP	Major capex project (as defined in the Transpower Capex IM), cost > $20m
MW	MegaWatt (power)
MWh	MegaWatt hour (energy)
NIC	New investment contract, aka TWA (Transpower works agreement)
NLD	Northland
NMB	Nelson Marlborough
NPB	Net private benefits
Opex	Operating expenditure, as defined in Transpower IMs
PAK	Pakuranga
PDP	Prudent discount policy
Pre-contingency load management	A plan to manage (reduce) load before an event to prevent unplanned loss of load after the event
Pricing year	A year starting from April, ending the next March, 1 April - 31 March
Producer surplus	The difference between the revenue that producers receive and their cost of production
R&R	Replacement and refurbishment investments, driven by asset condition assessments
RAB	Regulatory asset base
RC	Replacement cost
RCP	Regulatory control period (typically five years), the current period is RCP3 from 2020 – 2025
SACPD	Stand alone cost prudent discount
SDDP	Stochastic dual dynamic programming, the software typically used by Transpower to estimate market benefits for MCPs
SLD	Southland
SPD	The scheduling, pricing, and dispatch tool used by the system operator for dispatching generators, creating prices, and forecasting dispatch and prices
SPS	Special protection scheme
SRMC	Short run marginal cost, a producer's per unit operational cost
SSCGU	Substantial and sustained change in grid use
TCC	Transitional congestion charge
TIM	Timaru
TPM	Transmission pricing methodology

Term	Meaning
TPS	Transmission Pricing System
TWA	Transpower works agreement, aka NIC (new investment contract)
UNI	Upper North Island
USI	Upper South Island
VoLG	Value of lost generation
VoLL	Value of lost load
vSPD	Vectorised scheduling, pricing and dispatch model, software created as a publicly available replica of SPD (the scheduling, pricing and dispatch model used by the system operator)
WACC	Weighted average cost of capital
WKM	Whakamaru
WTK	Waitaki
WTN	Wellington
WTO	Waikato
WUNI	Waikato and Upper North Island
WUNIVM	Waikato and Upper North Island voltage management

TRANSPOWER

Chapter 2: Framework for our proposal

30 June 2021

Contents: Chapter 2

1 Introduction

1. This chapter describes the framework for developing a new TPM, which we have applied in preparing our proposal.

2 Framework for TPM Development

2.1 Statutory framework

2. The statutory framework for TPM development is set out in Subpart 4 of Part 12 of the Electricity Industry Participation Code 2010 (the **Code**).[1]
3. Under this framework, the TPM provides the basis on which the investment costs incurred by Transpower are recovered from designated transmission customers.[2]
4. The purpose of the TPM is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs of Transpower's services are allocated in accordance with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010 (the **Act**).[3]
5. Following incorporation into the Code, the new TPM will replace the existing TPM currently set out in Schedule 12.4 of the Code.[4] Once the Code is amended, the Authority has indicated that new prices consistent with the new TPM, will take effect from 1 April the following pricing year. The Authority anticipates this to be 1 April 2023.[5]

2.2 Thresholds for review of the TPM

6. The Code provides two mechanisms for the review of an approved TPM:
   6.1 **Transpower 'operational review'**: Transpower may submit a proposed variation to the approved TPM to the Authority, provided that submission is made at least 12 months after the last approval of the TPM[6] or

---

[1] Electricity Industry Participation Code (the **Code**) - Part 12 - Transport
[2] Code, clause 12.77. In this Reasons paper "customer" means a Transpower customer (i.e. a designated transmission customer).
[3] Code, clause 12.78.
[4] Code, clause 12.84.
[5] 2020 Decision, at 1.19 and chapter 17 (17.27, 17.31).
[6] Code, clause 12.85.

6.2 **Material change in circumstances**: The Authority may initiate a review of the approved TPM if it considers there has been a material change in circumstances.[7]

7. The Authority's 2019 Issues Paper summarises its reasons for considering that there had been a material change in circumstances since the TPM was introduced in 2008.[8] A list of key factors informing the Authority's decision that there had been a material change in circumstances are set out in paragraphs 4.25-4.35 of its TPM decision paper published on 10 June 2020 (**2020 Decision**).[9]

2.3 Authority's decision

8. On 10 June 2020, the Authority published:

8.1 its 2020 Decision setting out, amongst other things, the process for developing the new TPM;[10] and

8.2 the Guidelines Transpower must follow in developing the new TPM Guidelines (**Guidelines**).[11]

2.4 Timeframe and process for development

9. Transpower is required to submit its proposed TPM within 90 days (or such longer period as the Authority may allow) of receipt of a written request from the Authority.[12]

10. The 2019 Issues Paper indicated that the process should require Transpower to submit a draft TPM to the Authority by a specified date, somewhere between 12- and 18-months following publication of the Guidelines.[13]

11. The 2020 Decision confirmed **30 June 2021** as the deadline by which Transpower must submit its proposed TPM to the Authority.[14] On 10 June 2020, the Authority also wrote to Transpower requiring Transpower submit a proposed new TPM within this timeframe.[15]

12. Chapter 17 of the 2020 Decision describes steps for Transpower to follow in developing a proposed TPM, including providing the following Checkpoint submissions to the Authority as key milestones:

12.1 Checkpoint 1 – containing our key design choices for allocation methods for the benefit-based charge and any transitional congestion charge; and

12.2 Checkpoint 2 – containing our preliminary draft of a proposed TPM.

13. We agreed with the Authority an accelerated process for Checkpoint 1 in respect of the benefit-based charge, to provide an opportunity for engagement with our stakeholders on some of the more complex elements of the proposed TPM, particularly the benefit-based charge.

---

7 Code, clause 12.86.

8 Reference document #1 2019 Issues Paper. There have been various articulations of the material change in circumstance from the first, 2012, Issues Paper onwards.

9 Reference document #3 2020 Decision

10 Reference document #3 2020 Decision. The Authority's process and timeline decision for TPM Development is in Box 1, pages 111-112.

11 In accordance with clause 12.83 of the Code. (Reference document #4 Guidelines)

12 Code, clause 12.88.

13 Reference document #1 2019 Issues Paper, paragraph 6.12

14 Reference document #3 2020 Decision, paragraph 17.2

15 Reference document #5 Letter from EA: Development of a proposed new TPM

14. We also agreed with the Authority an extended timeframe for the Checkpoint 1 process for our initial analysis for any transitional congestion charge (TCC), to allow for the opportunity for feedback from industry participants.[16]

15. We agreed with the Authority early submission of elements of our preliminary proposal for Checkpoint 2 (connection charges, residual charge, transitional cap) to allow the Authority to stage its review and feedback on the Checkpoint 2 submissions, and allow us to focus on more complex elements of the proposed TPM. The remaining elements of the proposed TPM were submitted to the Authority in accordance with the Checkpoint 2 process set out in the 2020 Decision.

16. Transpower's Checkpoint submissions have been published on our TPM development page.[17]

17. A key part of our TPM development process was stakeholder engagement. Box 1 of the 2020 Decision provides that, while Transpower was "*not to engage with stakeholders on policy matters that have already been covered in the Authority's consultation on its proposed guidelines*", Transpower's engagement "*should concern detailed matters of TPM development within the guidelines set by the Authority*".[18]

18. Accordingly, we designed our stakeholder engagement approach to give industry visibility in relation to key topics forming part of our proposed TPM. Our stakeholder engagement on select focus areas has informed the content of our Checkpoint 2 submissions (preliminary proposals) to the Authority, and the options we considered in preparing our final proposal. Further detail on our stakeholder engagement is provided in the substantive chapters below. A high-level flowchart depicting our stakeholder engagement and checkpoints process is included at the end of this chapter.

2.5 The 2020 Guidelines

19. The new Guidelines were published by the Authority on 10 June 2020 under clause 12.83(b) of the Code.[19] The Guidelines require the new TPM to include the following components:

    19.1 a connection charge to charge designated transmission customers to recover the cost of connection assets that connect customer's assets to the interconnected grid;

    19.2 a benefit-based charge (**BBC**) to recover the costs of post-2019 and certain pre-2019 investments in the interconnected grid from customers in accordance with the positive net private benefits they are expected to receive from those investments;

    19.3 a residual charge to recover remaining transmission costs not recovered through other transmission charges, and ensure Transpower can recover up to its recoverable revenue in any pricing year;

    19.4 a prudent discount policy to allow Transpower to discount transmission charges for a customer whose charges would otherwise exceed the stand-alone cost of supplying them, or inefficiently bypass the grid;

---

[16] We agreed with the Authority an approach and indicative timetable to progress the potential TCC, including industry engagement activities to inform our Checkpoint 1. In our Checkpoint 1 re-submission, we communicated our reasoning to the Authority for not proposing a TCC. On this basis, we did not progress this topic through Checkpoint 2.

[17] TPM Development Project Timeline

[18] Reference document #3 2020 Decision, Box 1.

[19] Reference document #4 Guidelines

19.5 a transitional price cap on certain transmission charges to limit electricity bill price shocks from the initial rebalancing of transmission charges; and

19.6 "additional components" to be incorporated if doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that additional component, including an optional transitional congestion charge.[20]

20. The 2020 Decision further describes the key features of the Guidelines, and the Authority's reasons for including the relevant components.[21]

2.6 Form of new TPM and relevant considerations

Key requirements

21. Transpower is required to develop the TPM consistent with:

- any determination made under Part 4 of the Commerce Act 1986;
- the Authority's statutory objective; and
- the Guidelines.[22]

22. We describe how each of these requirements has been addressed in Section 4 below.

Key principles

23. The Guidelines also prescribe a number of principles Transpower must, as far as reasonably practicable, use in selecting between different options, including:

23.1 setting charges in a way that:

- reflects the cost of providing customers with new investment in the grid, access to the parts of the grid relevant to them and use of the grid to transport energy;
- reflects the share of positive net private benefits those customers are expected to derive from the matters referred to above; and
- takes into account, and does not seek to replicate the effect of, other means of controlling demand, including nodal prices.

23.2 balancing the economic benefits and costs of precision with the economic benefits and costs of practical considerations including robustness, simplicity, certainty (including through limiting the need for Transpower to exercise discretion) and costs associated with developing, administering and complying with the TPM;

23.3 avoiding incentives for customers to avoid transmission charges in ways that cause economic inefficiency;

23.4 avoiding incentives for distributed generators to seek avoided cost of transmission payments, except to the extent the payments reflect a savings in the costs of transmission (not just a saving in transmission charges to the relevant customer);

23.5 avoiding discriminating between customers, except to the extent allowed by the Guidelines or otherwise necessary to achieve the statutory objective; and

23.6 allowing Transpower to recover up to, but no more than, our recoverable revenue.[23]

---

20 See also Reference document #3 2020 Decision, paragraph 1.4.
21 Reference document #3 2020 Decision, page 2.
22 Code, clause 12.89(1).
23 Reference document #4 Guidelines, general matters, clause 1.

24. These principles have been a key part of our decision-making framework in developing the proposed TPM, and have informed our approach to assessing different options.

25. The Guidelines also allow the TPM to differ from the particular requirements of the Guidelines (but not their intent) if Transpower considers, in its reasonable opinion, that doing so would better meet the statutory objective than complying with the Guidelines in their entirety. These are referred to as "clause 2 departures" and are discussed further in Section 4.5 below.

26. In addition, Transpower also developed "design principles" within these parameters to help guide the development of our TPM proposal, with a view to making necessary trade-offs between options which otherwise comply with the TPM Guidelines. These are summarised in Section 3.1 below.

2.7 Process for TPM finalisation

27. Following submission of Transpower's proposed TPM, the Authority may:

    27.1 decline to consider the proposal if, in its view, Transpower has provided insufficient information for the Authority to assess the matters required by the Code, in which case it must be re-submitted by a date specified by the Authority;[24] or

    27.2 consider the proposed TPM, following which the Authority may either approve the TPM, or refer it back to Transpower for further development if in its view it does not conform with the requirements of clause 12.89(1) of the Code, in which case Transpower will have 20 business days to re-submit.[25]

28. If the Authority has required re-submission, and considers that the revised TPM proposal still does not conform to the requirements of clause 12.89(1) of the Code, it may make the amendments it considers necessary to ensure the proposed TPM conforms to those requirements.[26]

29. Once the Authority is satisfied that the proposed TPM meets the requirements of clause 12.89(1) of the Code, it must publish and consult on the proposal as soon as practicable.[27]

30. Within 40 days of the submission expiry date (or such longer period as the Authority may allow), the Authority must consider submissions and make a decision on whether to incorporate the proposed TPM in the Code.[28] In determining the date on which the TPM must take effect, the Authority must consult with Transpower.[29] The Authority has indicated it anticipates new prices will take effect from 1 April 2023.[30]

31. Once in effect, transmission charges must be calculated in accordance with the new TPM (except in the case of particular contractual arrangements applying)[31] and paid by customers accordingly.[32]

32. This process for TPM finalisation is summarised in Figure 1 below.

---

[24] Code, clause 12.90.
[25] Code, clause 12.91(1).
[26] Code, clause 12.91(2)
[27] Code, clause 12.92(1).
[28] Code, clause 12.93.
[29] Code, clause 12.94.
[30] Reference document #3 2020 Decision, paragraph 1.19.
[31] Code, clause 12.95.
[32] Code, clause 12.77.

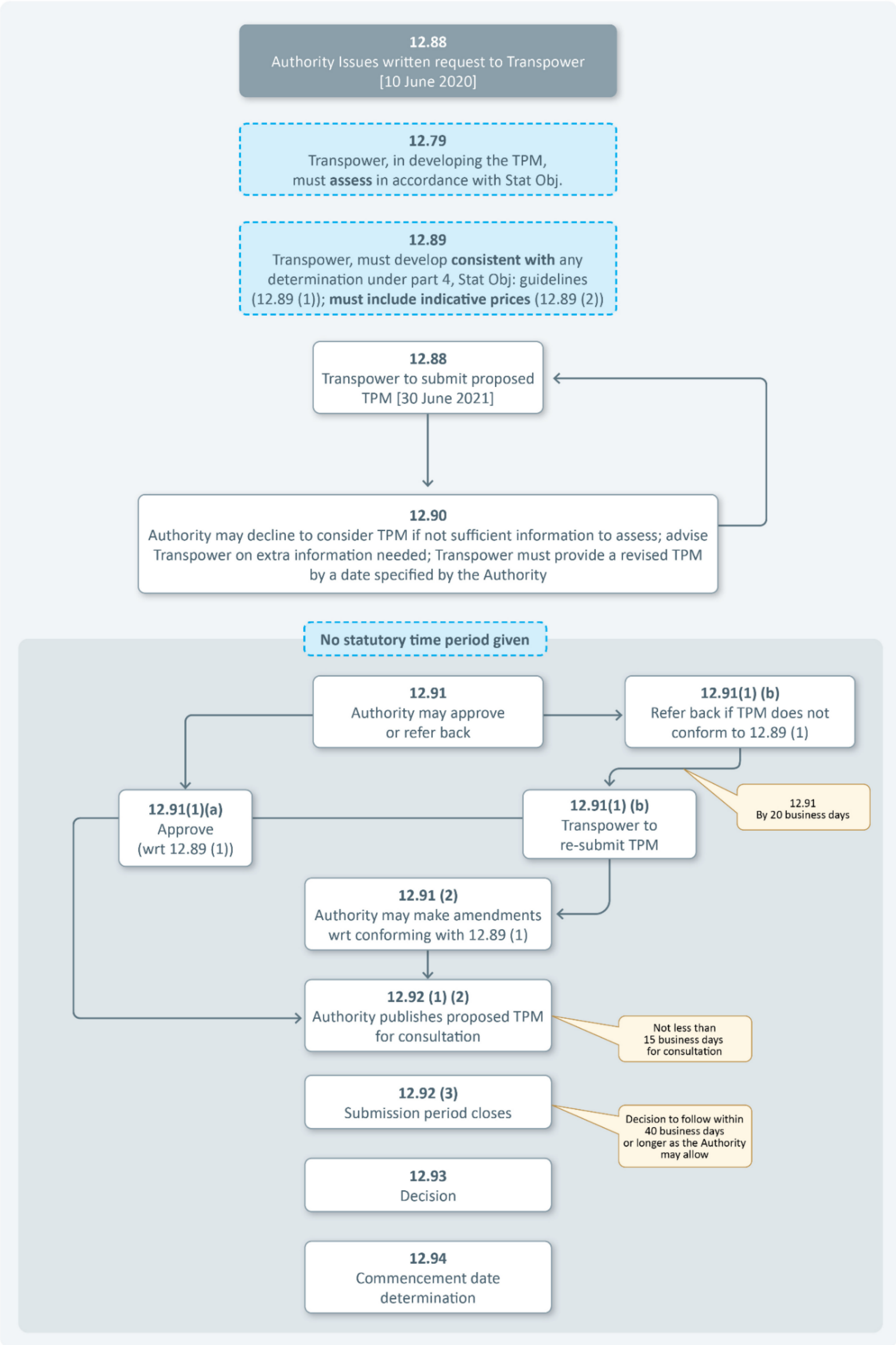


Figure 1 Code process for TPM finalisation

2.8 Secondary documents

33. Consistent with the new Guidelines, the new TPM involves a number of significant changes to transmission pricing in New Zealand. Matters of operational detail will need to be developed and refined in the lead-up to, and during, implementation. While our view is that structural and fundamental aspects of the proposed methodologies have been incorporated into the TPM consistently with the Guidelines, there is a role for secondary documentation to be developed to help ensure consistent and transparent application at the operational level.

34. For this reason, our proposed TPM requires Transpower to develop an "assumptions book" for the BBC, and also provides an option to develop similar "practice manuals" for reassignment and the prudent discount policy, as secondary documents that can be periodically updated as required from time to time.[33] The proposed TPM prescribes the purpose of these documents and also establishes certain procedures for their development, including publication and consultation requirements. The TPM also provides the safeguard that these secondary documents must not be inconsistent with the Code, including the TPM itself.[34]

35. As more operational information is gathered throughout implementation, and the matters set out in the secondary documents are periodically reviewed and (if necessary) updated, it may be beneficial to consider formally incorporating certain aspects of the operational documents into the TPM where they have proven to be relatively fixed or stable over time (e.g. certain operational assumptions).[35] While the secondary documents will already be publicly available to our stakeholders and formal incorporation is not necessary for our TPM to be workable, this would allow for improved ease of access, certainty and simplicity. For this reason, as part of its broader assessment of any Code changes required in connection with TPM development, Transpower invites the Authority to consider whether there would be merit in qualifying clause 12.85 to allow Transpower to propose a variation of the TPM more frequently than 12 months after the Authority last approved the TPM to allow such matters to be graduated into the TPM over time. Further detail of potential Code changes the Authority may wish to consider as part of its suggested "workability" amendments is set out in Chapter 16.

3 Stakeholder engagement process

36. Transpower values customer and industry views and recognises the importance of the TPM for our customers and the industry, generally. Throughout our development process, stakeholder engagement has been important to ensure we developed a workable TPM proposal. We have engaged with our stakeholders to the extent practicable within the timetable for development of the proposed new TPM, at key junctures designed to complement our work as part of the Checkpoint process.

---

33 See clause 39 (assumptions book), clause 107 (reassignment practice manual), clause 123 (prudent discount practice manual) of the proposed TPM.

34 Clauses 39(2), 107(2), and 123(2) of the proposed TPM.

35 Periodic reviews of the operational documents for this purpose are provided for in clauses 39(6), 107(6) and 123(6) of the proposed TPM.

37. Our stakeholder engagement processes, workshops and online sessions have helped us to better understand different customer and industry perspectives and balance competing considerations when making decisions on aspects of the proposed TPM.

3.1 Framework for stakeholder engagement

Designing our stakeholder engagement strategy

38. In submissions to the Authority during its TPM review, Transpower emphasised the importance of meaningful engagement with stakeholders as part of TPM development.[36] In its 2020 Decision, the Authority noted our view that constructive and highly engaged stakeholder participation would be a key contributor to the successful development and implementation of a new TPM.[37]

39. The Authority's process decision confirmed its support for Transpower to engage stakeholders as part of our TPM development process, provided the scope and duration of our engagement meant we met the 30 June 2021 final proposal deadline and did not engage with stakeholders on policy matters the Authority had already covered in its own consultation process.[38]

40. In developing the proposed TPM, we focused our stakeholder engagement on particular aspects of the proposal – primarily areas where the Guidelines afforded Transpower discretion to develop a method and/ or choose between options (as opposed to topics where the Guidelines were already relatively prescriptive).

41. To help focus our process, we published draft design principles that would help guide the development of our proposed TPM and complement those in the Guidelines, and sought feedback from our stakeholders. The five design principles we developed, and which have informed our work on the TPM, were:
    - Prices are explainable, including the way they change over time
    - The methodology is robust and transparent
    - The methodology limits reliance on undue discretion or subjective judgement
    - The methodology works constructively alongside the investment test
    - The pricing model is cost-effective to administer.

42. We developed an engagement approach consistent with Transpower's principles of engagement, outlined in our Customer Engagement Plan[39]:

    > For engagement to be truly meaningful, provide transparency and support the achievement of objectives of everyone involved, the design of an engagement process must be guided by the following principles:
    > - Approach to engagement is developed collaboratively
    > - Engagement is transparent and responsive to feedback
    > - Engagement is continuous with key milestones clearly identified
    > - Engagement occurs via multiple channels

---

36 For example, in Transpower's submission to the 2019 Issues Paper Attachment C – response to Question 7

37 Reference document #3 2020 Decision, paragraph 17.16.

38 Reference document #3 2020 Decision, Box 1.

39 Transpower Customer Engagement Plan for RCP3, section 4.2. This plan included a Customer Survey, issued in July 2020, to better understand our customers' perceptions of interacting with us. Feedback was used to inform the Principles of Engagement.

- Engagement is supported by information that informs and educates
- Engagement is targeted at those impacted

Consultation by the Authority

43. Our stakeholder engagement approach reflected that formal consultation on the proposed TPM would occur after 30 June 2021 by the Authority.
44. The Code requires the Authority to consult on the proposed TPM, following receipt of the draft from Transpower and any amendments requested or made by the Authority.[40] In its letter to the TPM Group, the Authority noted that: "*The Authority intends to carry out a substantive and meaningful consultation. Stakeholders will have an opportunity to make submissions on any aspect of the proposed TPM developed by Transpower. The Authority will take submissions into account and make any amendments it considers appropriate in response to matters raised in submissions before making its decision on whether to incorporate the proposed TPM into the Code.*"[41]
45. In response to requests for Transpower to undertake additional stakeholder engagement during the TPM development period, the Authority noted: *"The Authority does not consider it necessary for Transpower to engage with stakeholders on the full TPM in the period after Checkpoint 2 and before the 30 June deadline, or for the TPM development timeframe to be extended for this purpose."*[42]

3.2 Our approach and process – major review stages

46. The table below outlines our engagement approaches and key actions for TPM development as they align to Transpower's seven customer engagement principles:

Table 1 Engagement approaches (principles) and key actions

Principle	Our response
Transpower's engagement with the industry on the TPM beneficial to all parties	Throughout the TPM proposal development process, we have sought to enable meaningful stakeholder engagement where possible. Working with the prescribed Checkpoint delivery timetable and 30 June deadline, we incorporated engagement processes as we could, including by providing opportunities for cross-submission at each stage. We ensured stakeholders were regularly updated through our TPM notifications and had the opportunity to engage us through our TPM inbox (tpm@transpower.co.nz). We accelerated our process for Checkpoint 1 (our initial analysis for benefit-based charges) to provide a window for engagement with stakeholders on the more complex aspects of the Guidelines. We remained responsive to feedback throughout the process, including through adding a batteries and storage engagement process to our schedule, in response to a request by the Authority to consider this issue as part of TPM development, which was of interest to many of our stakeholders.

40 Code, clause 12.92.
41 Letter from James Stevenson-Wallace to TPM Group, 21 January 2021, page 1.
42 Letter from James Stevenson-Wallace to TPM Group, 21 January 2021, page 1.

Approach to engagement is developed collaboratively	We established and maintained regular engagement with the Authority, meeting frequently with their TPM team (and convening senior leadership/Board meetings where appropriate). We published key documents and letters once the Authority had provided feedback and understood our approach, to ensure stakeholders had visibility of the documents in light of the Authority's feedback. With stakeholders, as above we sought feedback on our project design principles from the start (August 2020) and after reviewing submissions we revised our design principles. This included making it clearer they sat under the TPM Guidelines, the Authority's statutory objective and any determination by the Commerce Commission under Part 4 of the Commerce Act. We published feedback, a summary of the feedback, our response and our final design principles.
Engagement is transparent and responsive to feedback	To ensure transparency, we published relevant information to our TPM webpages. We aimed to be consistent and timely. We published: • our design principles, development process and project timeline (and an updated timeline in early 2021); • regular updates (notifications to our newsletter subscribers); • questions (and our answers) received via our inbox; • Checkpoint documents and letters with the Authority; • stakeholder engagement documents, submissions, cross-submissions and our summary & response documents; • workshop details and recordings (with transcripts); and • online drop-in session details and recordings (with transcripts). We also included additional links, where appropriate, and background material. To ensure we reached stakeholders who may not have subscribed to our TPM newsletter, we included regular updates in Transpower's Industry Update newsletter. Our approach was to manage expectations upfront through clear messages on scope, including aspects of the TPM not subject to stakeholder engagement. Where there was scope for feedback, we prioritised engagement as best we could. We were open with stakeholders that there was insufficient time following Checkpoint 2 to engage with stakeholders on the draft proposed TPM, and that formal consultation would be undertaken by the Authority. However, we did publish a preliminary draft of our TPM proposal with our Checkpoint documents on 25 May, which included areas the Authority requested us to consider as we finalised our proposal.
Communication is continuous with key milestones clearly identified	After establishing our TPM webpages and mailing list, we published our timeline (and an updated version in March 2021) and sent regular notifications (42 from 10 August 2020 to 2 June 2021 with 178 subscribers as at 2 June 2021). We clearly communicated our stakeholder engagement dates and processes and endeavoured to apply a consistent approach.
Engagement occurs via multiple channels	We established dedicated webpages, a regular dedicated newsletter and actively managed a TPM inbox. We also included regular updates in our Transpower Industry Update newsletter. We established various

	channels, including workshops and online drop-in sessions, and a Q&A platform.
Communication is supported by information that informs and educates	We endeavoured to ensure TPM content we published was prepared and presented in a way that was accessible and understandable, while having regard to the complexity of the subject matter.
Engagement is targeted at those impacted	We acknowledged early on the implications a new TPM would have for our customers and broader industry participants and stakeholders interested in the TPM. We promoted our TPM newsletter and key milestones early on through the Authority's Market Brief, Transpower Grid Pricing Strategy Manager and Transpower Customer Solutions Team. In November 2020, we undertook a stakeholder audit to ensure key stakeholder organisations impacted and/or interested in a new TPM were represented on our newsletter subscription list.

3.3 Topics we sought feedback on

47. In designing our stakeholder engagement approach, within the timeframe available, we focused on key aspects of the new TPM likely to be of material interest to our stakeholders, including where the Guidelines allow for Transpower to apply discretion in deciding between different options, and noting the Authority itself will consult on the full TPM proposal.

48. Since August 2020, we ran five stakeholder engagement processes, three online drop-in sessions and two online workshops.

49. We sought stakeholder feedback on our initial thinking for:
    - Connection Charges;
    - Transitional Congestion Charge;
    - First Mover Disadvantage;
    - Prudent Discount Policy;
    - TPM Options for a Benefit-Based Charge and Adjustments; and
    - Application of the Residual charge to Battery Storage.

50. For each process, we ensured the timely publishing of our stakeholder engagement material, all submissions and cross-submissions received, and our summary and response documents, and sent notifications to our TPM newsletter subscribers when there were new developments and/or documents published. Key stakeholder engagement materials and workshop documents, and associated materials, remain available on our TPM development webpages.[43]

3.4 Transparency and keeping stakeholders informed

51. As part of our commitment to ensure stakeholder engagement was transparent and responsive, we published a summary and response document on each topic we sought feedback on, after reviewing all submissions and cross-submissions. Our summary and response documents outlined how stakeholder feedback informed our thinking at the time.

[43] TPM Development Project

52. We are grateful for all stakeholder feedback and insights we received through our engagement processes, which helped informed the development of our TPM proposal.

4 Development of our TPM Proposal

53. In preparing our proposed TPM, we carefully considered the choices available to us within the parameters set by the Guidelines and taking into account feedback received from the Authority, customers and other stakeholders during development.
54. Where the Guidelines prescribed a particular position or method, we have implemented that position in the proposed TPM, unless we have proposed a departure from a particular requirement of the Guidelines under clause 2.
55. Where we were afforded discretion to select between alternatives or develop a specific methodology, we undertook a detailed assessment to formulate options, balance relevant considerations and select a preferred approach. In doing so, we have, as far as reasonably practicable, used the principles in clause 1 of the Guidelines as we are required to, and sought to ensure the consistency with the broader framework for TPM development, including the Authority's statutory objective.
56. The views of customers and stakeholders have been invaluable to this exercise. Throughout our TPM development process, we have sought and been assisted by industry feedback on key aspects of the new TPM. We have also received feedback from the Authority throughout our Checkpoint process, which has been carefully considered in developing and refining our final proposal.
57. The balance of this section explains how our proposed TPM meets the key regulatory criteria for a new TPM, including consistency with the Guidelines, the statutory objective and relevant Part 4 determinations.[44]

4.1 Consistency with Guidelines

58. The Guidelines provided the foundation for our task and guided (and also constrained) the choices we were able to make as part of TPM development.
59. In preparing the proposed TPM, we implemented the requirements of the Guidelines, including, so far as reasonably practicable, using the principles in the Guidelines. We have also endeavoured to ensure consistency with the Authority's intent.[45] Our proposed TPM complies with the Guidelines, except where we have proposed a 'clause 2 departure' from a particular requirement of the Guidelines, as discussed in the following chapters.
60. We note that while some components of the Guidelines are very prescriptive, others afford Transpower discretion to choose between available options, or develop specific methodologies. In selecting between options which otherwise comply with the Guidelines, we have, as far as reasonably practicable, used the principles set out in clause 1 of the Guidelines as required. These principles have been core to our task. This has included developing our proposal in a way that reflects the matters set out in clause 1, taking into account matters such as balancing the economic benefits and costs of precision of the TPM

[44] Code, clause 12.89(1).
[45] For example, the "Authority's intent" section of the Guidelines, page 2-3.

with the economic benefits and costs of practical considerations including: robustness, simplicity, certainty and costs, and other matters such as incentive impacts and avoiding discrimination.[46]

61. The individual chapters of this reasons paper contain our detailed reasoning for each component, and outline how our proposals are consistent with the Guidelines and their intent, including by reference to the above principles.

4.2 Consistency with the statutory objective

Our role

62. The Code places the obligation on the Authority to develop Guidelines for TPM development which uphold the statutory objective.[47] In its 2020 Decision, the Authority provides an explanation of why it considers the Guidelines advance the statutory objective.[48]

63. Transpower's role is to develop the TPM in accordance with those Guidelines.[49] Accordingly, as above, we have implemented the requirements of the Guidelines in developing the proposed TPM (except where we have proposed a specific departure). In doing so, we have not revisited the merits of the Guidelines, or the extent to which they best promote the statutory objective. This is not our role. Rather, we are required to take the Guidelines as published by the Authority.

64. The statutory objective has nonetheless needed to inform our approach to TPM development, as required by the Code,[50] and we have considered relevant options against the statutory objective, namely in relation to:

    64.1 topics where the Guidelines were not prescriptive and afforded Transpower discretion to apply its judgement and expertise consistently with the Guidelines principles (for example where we were required to develop a method, choose between options, or where we have needed to include additional or complementary content to ensure the TPM as a whole is clear, coherent and workable within the parameters set by the Guidelines); and

    64.2 topics where we have proposed a 'clause 2 departure' from a particular requirement of the Guidelines, on the basis doing so would better advance the statutory objective while still meeting the Authority's intent, or to adopt an Additional Component.

65. The next section provides a further overview of how we have applied the statutory objective.

Applying the statutory objective

66. The Authority's statutory objective is set out in section 15 of the Act, which provides:

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

67. We have considered and applied the statutory objective to relevant aspects of our proposal (for example, where the Guidelines were not prescriptive). The detailed chapters discuss the

---

46 Guidelines, General matters, clause 1.

47 Code, clause 12.81(2): "*The process and guidelines must be developed in accordance with the Authority's objective in section 15 of the Act*".

48 Reference document #3 2020 Decision, paragraphs 4.16-18.

49 Code, clause 12.89(1).

50 Code, clause 12.79 and 12.89(1).

key areas where we have considered and developed relevant components by reference to the statutory objective.

68. As discussed above, in developing the TPM in accordance with the Guidelines, we are required, as far as reasonably practicable to use the principles set out in clause 1 of the Guidelines. Accordingly, at the level of specific issues and choices Transpower has been required to make in developing the TPM, applying the statutory objective primarily required us to have regard to considerations within those principles, including principles concerning robustness, simplicity and certainty. Where the Guidelines have required us to balance economic benefits and costs of precision against the benefits and costs of practical considerations, we have done so having regard to the statutory objective.

69. Our approach has reflected our view that the statutory objective is enhanced by proposing parameters, rules and methodologies in the TPM that provide certainty and transparency, but which also contain flexibility where necessary to avoid false precision and enable matters of operational detail and specific input assumptions to be refined during implementation.

70. We have also had regard to the statutory objective in determining whether to propose a clause 2 departure to a Guidelines requirement, and adopt the Additional Components. An example of the former is the process we followed regarding the application of the residual charge to grid-connected batteries, on which we sought feedback from our stakeholders. In considering whether to exempt batteries from the residual charge was an option available to us that would "better meet" the statutory objective, we gave weight to the importance of avoiding solutions that could be discriminatory or ad-hoc. While in that case, we were not able to reach a conclusion that departing from the Guidelines better met the statutory objective, this informed the framework for our assessment and helped highlight the broader policy issues at stake.

4.3 Consistency with determinations under Part 4 of the Commerce Act

71. Consistency with determinations made by the Commerce Commission under Part 4 of the Commerce Act can have two aspects: ensuring there is no conflict between the TPM and any Part 4 determinations, and ensuring there are no gaps between the revenue that is determined to be recoverable under Part 4 and what the TPM permits Transpower to do.

72. We have had regard to both forms for consistency. We are not aware of any conflict between the Proposed TPM and any Part 4 determinations, and no such conflict has been brought to our attention throughout the TPM development process.

73. Our proposals are aligned with our Capex IM,[51] and designed to ensure cost recovery in relation to our approved investments.

74. We have also been mindful that the TPM must provide for recovery of all expenditure approved by the Commerce Commission under Part 4 (i.e. there should be no gaps). This is achieved, in part, through the residual charge, the purpose of which is to enable recovery of Transpower's recoverable revenue in any pricing year in a way that minimises impacts on customer decision-making, and is available for any remaining revenue not allocated and recovered through other transmission charges (such as the BBC and connection charges). The TPM also enables recovery of investments that have been approved and made in anticipation of demand, including as part of broader investments initiatives aimed at

[51] Reference document #71 Transpower Capex IM

facilitating the decarbonisation of the economy and increasing energy security. This issue is discussed further in later chapters – see in particular the "First Mover Disadvantage" section of Chapter 5 –Connection Charges, which relates to investments designed to improve capacity and anticipate future demand for transmission services.

4.4 Additional components

75. The Guidelines provide the option to incorporate up to seven additional components into the proposed TPM if Transpower considers, in its reasonable opinion, for each additional component, that doing so would better meet the Authority's statutory objective than not including the additional component.[52] For any additional components Transpower does decide to include in the proposed TPM, the implementation of those additional components can be deferred if necessary to expedite implementation of the BBC.

76. A summary of our decisions for each additional component are set out in chapters 14 (for additional components A (adjustments to charges for staged commissioning), B (charges for assets that in substance principally provide connection services), C (charges for connection investments to use a method substantially the same as for benefit-based charges), E (extension of benefit-based charge), F (allocation of opex) and G (kVAr charge)) and 15 (additional component D – transitional congestion charge).

77. Our proposed TPM includes additional components A and B. Our proposed TPM does not include additional components C, D, E, F and G.

4.5 Clause 2 departures

78. Clause 2 of the Guidelines allows Transpower to depart from the particular requirements of the Guidelines, but not their intent, where Transpower reasonably considers that doing so would better meet the Authority's statutory objective than complying with the Guidelines in their entirety. Where we have proposed a specific departure, this is detailed within the relevant chapter below, including our reasoning and – if applicable – the alternatives we considered in reaching our view.

79. Included in Appendix A to this paper is a summary list of clause 2 departures we have proposed, as required by clause 4 of the Guidelines.

4.6 Material assumptions

80. The material assumptions that have informed our proposal are set out in the following chapters as we discuss the choices we have made and why we have made them.

[52] Reference document #4 Guidelines, clause viii and 54.

Stakeholder engagement process timeline

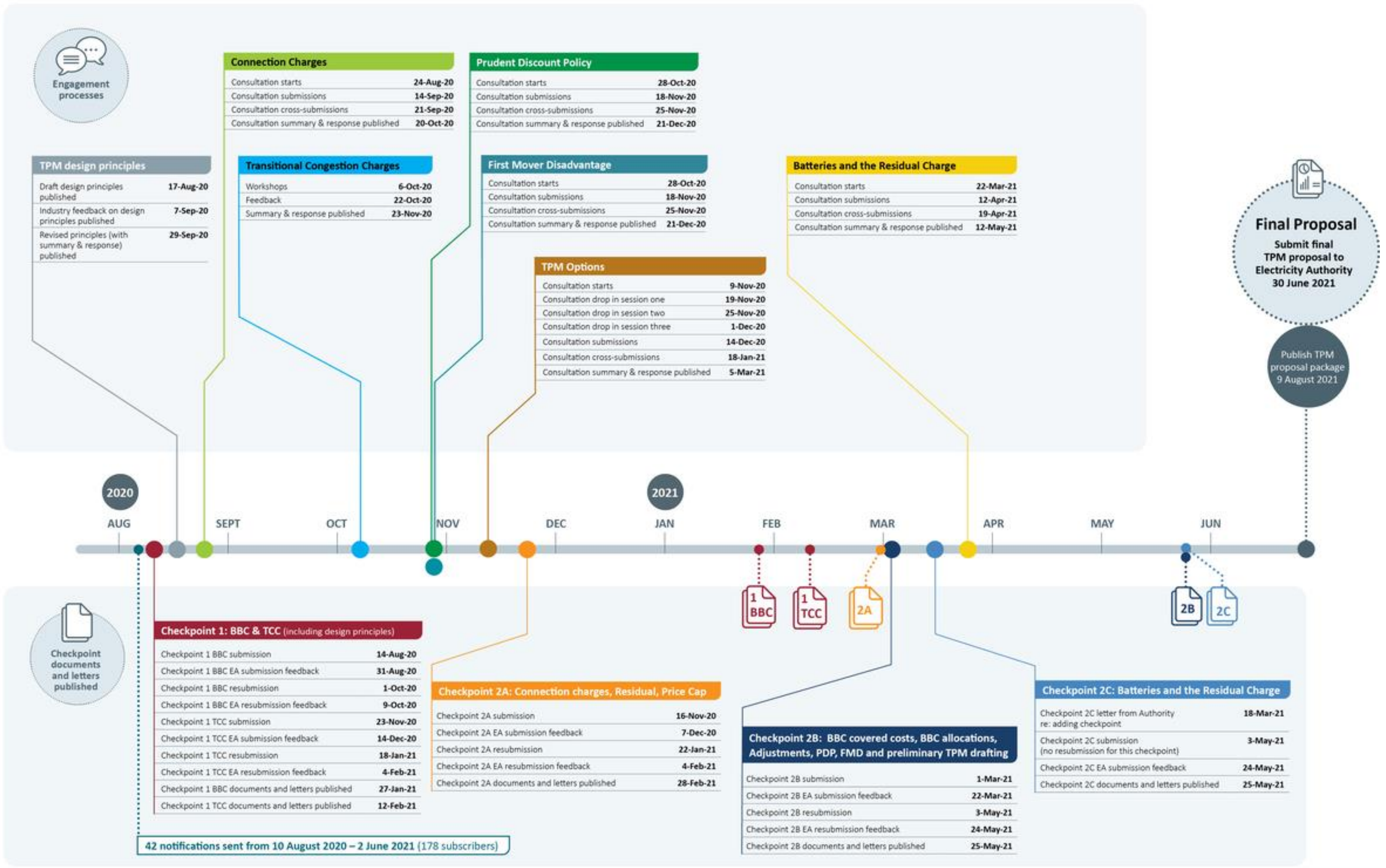


Figure 2 Stakeholder engagement and checkpoints timeline

TRANSPOWER

Chapter 3: Part A – Preliminary

30 June 2021

Contents: Chapter 3

1 Introduction

1. This chapter summarises and explains our proposals for certain preliminary provisions of the proposed new TPM.
2. Part A of the proposed TPM contains definitions and other provisions of general application to transmission charges, some of which are discussed in other chapters of this paper.
3. This chapter discusses some general drafting improvements we have made in the proposed TPM and covers the following matters in Part A of the proposed TPM, which are not discussed in other chapters:

    3.1. consultation on transmission charges;

    3.2. information about transmission charges.

    3.3. treatment of transmission alternatives;

    3.4. timing of commissioning, connection and disconnection;

    3.5. separate calculation of transmission charges;

    3.6. calculations, estimations and determinations under the TPM;

3.7. exceptional operating circumstances (**EOC**); and

3.8. applications under the TPM.

2 Requirements of the Guidelines

4. The Guidelines contain clauses relating to consultation on transmission charges (clause 5), information about transmission charges (clause 6), and the treatment of transmission alternatives (clause 9).

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

   a. the proposed connection charge for each connection investment;

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

   c. the proposed allocation of the **residual charge**;

   d. any transitional **congestion charge**;

   e. any kvar charge; and

   f. any proposed material changes to those charges (other than the total **residual charge**) or their allocations (in which case consultation must extend to whether and on what basis such changes are warranted under these **Guidelines**),

   with parties who have a material financial interest in the respective 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 charges** 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** or, where applicable, as a result of a prudent discount. Information provided for the purposes of this clause should be sufficient to enable the designated transmission customer to understand the basis for Transpower's calculations of its **transmission charges**.

...

9. The **TPM** must provide for the treatment of a transmission alternative to be consistent with the treatment the type of **investment** (I.e. **connection investment** or **benefit-based investment**) which the transmission alternative seeks to avoid would have received under these **Guidelines** or, where this is not reasonably practicable, the cost of transmission alternatives must be allocated to the designated transmission customers that benefit from them in proportion to Transpower's reasonable assessment of the relative level of **positive net private benefit** that each customer receives from them.

3 Stakeholder engagement and process

3.1 Consultation

5. In August 2020, we released a consultation paper seeking feedback on options for connection charges (our connection charges consultation paper). The preliminary TPM drafting we released with our connection charges consultation paper included:

   5.1. a number of improvements on the drafting of those parts of the current TPM relating to grid asset classification and connection charges; and

   5.2. provisions relating to (a) the separate calculation of transmission charges, and (b) calculations and determinations under the TPM.

6. Our connection charges options consultation paper, submissions and cross-submissions are available on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[1]

7. In October 2020, we released a consultation paper seeking feedback on options for the prudent discount policy (our PDP consultation paper), including preliminary TPM drafting. In our PDP consultation paper we proposed:

   7.1. Introducing application fees for prudent discount applications; and

   7.2. publishing the detailed content requirements for prudent discount applications on our website rather than in the TPM itself (as is currently the case).

8. Our PDP consultation paper, submissions and cross-submissions are available on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[2]

9. We have taken the submissions and cross-submissions on our connection charges and PDP consultation papers into account in preparing the proposed TPM.

3.2 Checkpoint 2

10. In November 2020, we submitted our preliminary proposals for residual charges and the transitional cap to the Authority as part of its Checkpoint 2 process (our Checkpoint 2A submission).[3] The preliminary TPM drafting the submitted with our Checkpoint 2A submission included the EOC mechanism. In its feedback on our Checkpoint 2A submission, the Authority confirmed it had *"no substantive concerns"* with the inclusion of the EOC mechanism in the new TPM.[4]

11. In March 2021 and May 2021, we submitted further preliminary TPM drafting to the Authority as part of its Checkpoint 2 process (our Checkpoint 2B submission and resubmission).[5] The preliminary TPM drafting included provisions relating to all of the matters covered in this

---

1 TPM Development: Connection Charges consultation process.

2 TPM Development: Prudent Discount Policy consultation process

3 Reference Document #31 Checkpoint 2 submission: Residual Charge and Transitional Cap.

4 Reference document #35 Letter from EA: Checkpoint 2A submission, paragraph A.21(b).

5 Reference document #52 Checkpoint 2B submission (preliminary TPM and Reference document #64 Checkpoint 2 resubmission preliminary TPM drafting.

chapter. The provisions we submitted were similar to the equivalent provisions now in the proposed TPM. In response to our Checkpoint 2B resubmission, the Authority provided some feedback on the preliminary TPM drafting.[6]

12. We have taken the Authority's feedback on our Checkpoint 2 submissions and resubmissions into account in preparing the proposed TPM.

4 TPM drafting tidy up

13. We propose a number of drafting refinements in the proposed TPM, which we consider improve on the drafting of the current TPM in a number of ways:

13.1. **Fixing errors:** For example, "connected" is often bolded in the current TPM but is not used in its previous Code-defined sense (being distributed generation or a consumer installation "connected" to a distribution network). The definition of "connect" in Part 1 of the Code was revoked in 2017. The definition of "connected" in the proposed TPM is discussed in Section 8.

13.2. **Removing redundancy:** For example, we have used terms defined in Part 1 of the Code where possible instead of re-defining them in the TPM.[7]

13.3. **Reducing ambiguity:** For example, where possible we have replaced descriptions with formulaic expressions. We have also included worked examples of how some clauses would apply.

13.4. **Improving readability and accessibility (where we can[8]):** For example, we have added more diagrams and tables to help with understanding the concepts of connection and interconnection and the attribution of assets to connection locations and customers. We have also divided the proposed TPM into Parts and introduced a contents page.

13.5. **Aligning with Transpower's Part 4 Commerce Act 1986 regulation:** We have used new and replacement definitions based on the Commerce Commission's determinations applying to Transpower. For example, in Parts C and D of the proposed TPM the relevant inputs for the calculation of connection charges and covered cost are referenced to opening and closing RAB values, as defined in Transpower's input methodologies.

5 Consultation on transmission charges

14. Under clause 17(1) of the proposed TPM, we must consult on:

14.1. proposed annual connection charges and material adjustments to connection charges during a pricing year, with those customers who will pay the connection charges;

6 Reference document #69 Letter from EA: Checkpoint 2B resubmission Appendix E comments on preliminary TPM drafting

7 There are some terms defined in Part 1 of the Code that are not well-suited to the proposed TPM. For example, "injection" in Part 1 is defined as electricity flow into any network, whereas the proposed TPM (and the current TPM) uses the term to refer to electricity flow into the grid only. Accordingly, "injection" is re-defined for the purposes of the proposed TPM.

8 Overall, the Guidelines have led to a proposed TPM that is more complex and less accessible than the current TPM.

14.2. expected total covered cost and proposed starting allocations for each high-value post-2019 benefit-based investment (**BBI**), by way of public consultation;

14.3. proposed material adjustments to the expected total covered cost for each high-value post-2019 BBI, by way of public consultation;

14.4. proposed adjustments to the allocations for each high-value post-2019 BBI as a result of a substantial sustained change in grid use (**SSCGU**), by way of public consultation;

14.5. other proposed material adjustments to the allocations for each high-value post-2019 BBI, with the customers who are or will be beneficiaries of the BBI; and

14.6. the proposed allocation of residual charges for each pricing year and material adjustments to those allocations during a pricing year, with load customers.

15. The groups referred to in clause 17(1) of the proposed TPM are the parties we consider would have a "material financial interest" in the matters being consulted on (clause 5 of the Guidelines). The expected total covered cost (and material changes) and proposed starting allocations for a high-value post-2019 BBI are less formulaic than the other matters covered in clause 17(1), and have a less predictable set of interested parties. For these matters we propose to consult publicly. We also propose to consult publicly for allocation adjustments triggered by a SSCGU, which we propose will be by way of a full, intra-regional reallocation (see Chapter 10 (Adjustments) of this paper).

16. Our proposal for consultation on connection charges also reflects our long-standing, and to date uncontroversial, practice of only consulting on connection charges with those customers who pay them.

17. The groups referred to in clause 17(1) of the proposed TPM are minimum groups. We may choose to consult more widely than required under the TPM, if we consider the subject matter warrants it.

18. Some other points to note about consultation:

18.1. We expect our consultation obligations in the new TPM will sometimes be fulfilled by consultation through mechanisms outside the TPM, particularly under the Transpower capex input methodology[9] and our transmission agreements with customers.[10] Clause 5 of the Guidelines and clause 17(3) of the proposed TPM allow for this.[11]

18.2. Clause 5(b) of the Guidelines requires consultation on BBCs for "proposed" high-value BBIs only. Accordingly, the proposed TPM does not include an obligation for Transpower to consult on benefit-based charges (**BBCs**) for the historical BBIs in Schedule 1 of the Guidelines/Appendix A of the proposed TPM.

18.3. Although not required by the Guidelines, clause 17(2) of the proposed TPM requires us to consult publicly on the parameters for the simple method for allocating BBCs for low-value post-2019 BBIs.

---

9 Reference document #71 Transpower Capex IM, clauses 8.1.2 and 8.1.3.

10 Clause 41.5(b) of the Benchmark transmission agreement incorporated by reference in Part 12 of the Code (**Benchmark Agreement**).

11 We would not duplicate consultation that had already been, or was already being, carried out (footnote 6, Authority comment on clause 17(2) of the preliminary TPM drafting).

18.4. Clause 17(4) of the proposed TPM specifically requires consultation on any departures from the assumptions book when we consult on the allocations for high-value post-2019 BBIs and the simple method parameters.

19. We consider our proposal complies with clause 5 of the Guidelines.

6 Information about transmission charges

20. Under clause 18 of the proposed TPM, we must provide each customer with reasonable information sufficient for the customer to understand the basis on which its annual and monthly transmission charges, and changes to them, have been calculated. We propose to fulfil this obligation through the existing notification mechanism in transmission agreements.[12]

21. The information we provide to load customers must include unallocated operating costs and reassignment amounts included in residual revenue, and therefore the load customer's residual charge. As we are proposing to recover prudent discounts through a separate prudent discount recovery charge, a customer's contribution to any prudent discounts will be transparent.

22. Consistent with clause 6 of the Guidelines, the proposed TPM does not specify exactly how the information will be presented or how granular it will be. This is because we are yet to develop our notice and invoice templates for the new TPM. In any event, as is our current practice, if customers have questions about how their transmission charges are calculated then we will answer them. We expect customer feedback during the early years of the new TPM will help us refine our notices and invoices to ensure they contain the type and level of information customers find useful.

23. We consider our proposal complies with clause 6 of the Guidelines.[13]

7 Treatment of transmission alternatives

24. In the proposed TPM, the terms "connection investment" and "interconnection investment", and therefore "benefit-based investment", are defined to include transmission alternatives.

25. For transmission alternatives in connection investments,[14] clause 26(4) of the proposed TPM applies. The operating cost of the transmission alternative for a pricing year is shared between customers at the relevant connection locations in proportion to their total connection charges at those connection locations. Clause 26(4) of the proposed TPM mirrors the approach in clause 35(2) of the current TPM.

26. Transpower may, through the definition of "connection transmission alternative" in the proposed TPM, apportion the operating cost of a transmission alternative between connection

[12] Benchmark Agreement, clause 41.5.

[13] We do not consider clauses 7 or 9 of the Guidelines are directly relevant to clause 18 of the proposed TPM (footnote 6, Authority comment on clause 18 of the preliminary TPM drafting).

[14] We expect transmission alternatives for connection assets will be rare. In most cases, we expect any alternative to the grid at the connection level will be provided by customers rather than Transpower.

charges and BBCs/residual charges if the transmission alternative is an alternative for both connection and interconnection assets (mirroring clause 35(4) of the current TPM).

27. The costs of transmission alternatives in BBIs form part of the covered cost of the relevant BBI (clause 41(1) of the proposed TPM). This element of opex is attributed directly to the BBI, not by proxy.

28. We consider our proposal complies with clause 9 of the Guidelines (by treating transmission alternatives consistently with the type of transmission investment they avoid).

8 Timing of commissioning, connection and disconnection

29. Commissioning and connectivity are important concepts throughout the proposed TPM.

30. In clause 6(1) of the proposed TPM, the commissioning date for a grid asset is linked to the definition of "commissioned" in the Transpower input methodologies.[15] This is consistent with the definition of "commissioned" in the Guidelines.

31. If the grid asset is the first asset in a connection or interconnection investment to be commissioned, the grid asset's commissioning date will also be the commissioning date of the investment (unless there is an earlier-commenced transmission alternative in the investment). If the investment is a BBI, this will also define the commissioning date of the BBI.[16]

32. In clauses 7(a) and (b) of the proposed TPM, the timing of an asset's connection to or disconnection from a network (including the grid and a local network) is determined by when the relevant point of connection to the network is commissioned or decommissioned.[17] We have not used the existing Code definitions of "electrically connect" and "electrically disconnect" because they are operational definitions based on electricity flow, and a customer's connection status should not depend on whether it is choosing to use the network it is physically connected to.

33. Under clauses 7(d) and (e) of the proposed TPM:

    33.1. plant is connected to the grid only if it is directly connected to the grid; and

    33.2. embedded plant may be connected to a local network or grid-connected plant directly or indirectly (through other plant or a non-grid network).

    Making this clear up-front helps ensure there is no ambiguity in the later drafting.

9 Separate calculation of transmission charges

34. A customer may be both a load customer (including an offtake customer) and an injection customer during the same trading period, including at the same connection location and point of connection to the grid.

---

15 Reference document # 72 Transpower IMs, clause 1.1.4(2).

16 Clause 6(3) of the proposed TPM also contains a definition of "fully commissioned" which is used primarily in relation to allocating BBCs.

17 "Decommissioned" is defined in Part 1 of the Code in a TPM-appropriate way.

35. Consistent with clause 25(1) of the current TPM, clause 11 of the proposed TPM provides for transmission charges to be calculated separately for a customer in its capacity as a load customer and injection customer (if the customer has multiple capacities).

36. For example, a grid-connected generator will be treated as an offtake customer (direct consumer), and therefore a load customer, for those trading periods it takes electricity from the grid. A consequence of this is that a grid-connected generator may pay a (relatively small) residual charge.

10 Calculations, estimates and determinations under the TPM

37. Clauses 12(1) and (2) of the proposed TPM clarify that, except as otherwise stated (for example, where the TPM requires Transpower to use particular inputs for a calculation or estimate):

    37.1. calculations and estimates under the TPM are carried out by Transpower;

    37.2. Transpower may determine the inputs to those calculations and estimates; and

    37.3. Transpower may use its modelling tools, as necessary, to carry out those calculations and produce those estimates.

38. Clauses 12(3) and (4) of the proposed TPM specify the level of precision required for certain calculations and estimates and allow Transpower to scale allocators up or down to eliminate rounding errors.

39. Clause 13 of the proposed TPM expands on clause 7(h) of the current TPM. A determination by Transpower must not only be reasonable (as required by the current TPM) but must also be made in accordance with generally accepted accounting practice (**GAAP**) in New Zealand and with reference to relevant information made available to us and which we are reasonably able to obtain. The requirements of the TPM prevail if there is any inconsistency with GAAP.

40. All references in the proposed TPM to Transpower "determining" values or other things are subject to clause 13.

11 Exceptional operating circumstances

41. Clause 15 of the proposed TPM allows Transpower to adjust "allocation data" (data, including metering information, relevant to allocating transmission charges) to mitigate or eliminate distortions caused by exceptional operating circumstances in the power system arising from Transpower's requirements or outages in the grid (referred to as EOC).

42. The EOC mechanism is in clause 34(2) of the current TPM. The mechanism has been applied 52 times since 2010, the last time being in May 2018 for an unplanned tripping of BAL-HWB circuit 1, which resulted in the notionally embedded generation at Waipori being unavailable to Aurora Energy.

43. The EOC mechanism is not referred to in the Guidelines (and was not referred to in the previous TPM Guidelines either). However, we do not consider our inclusion of the EOC mechanism in the proposed TPM to be a departure from the requirements of the Guidelines. We consider this proposal to be filling a gap.

44. The EOC mechanism may be more important in the new transmission pricing regime than the current one (despite the removal of peak-based transmission charges) because transmission charges will be relatively fixed in future. Anomalous power system conditions could therefore become locked into transmission charges for longer. This may distort the incentives the new transmission charges are designed to bring about and be unfair. On that basis, we consider including the EOC mechanism in the proposed TPM to be consistent with the efficiency limb of the Authority's statutory objective.[18] The mechanism is also consistent with the principle in clause 1(b)(i) of the Guidelines because it will make the new TPM more robust, albeit slightly less certain, than without it.

45. For these reasons, even if the EOC mechanism were a departure from the requirements of the Guidelines, we consider it could be justified under clause 2 of the Guidelines (noting there is no expression of contrary intent in the Guidelines or any other relevant Authority documentation).

46. Clause 14 of the proposed TPM contains a similar mechanism for adjusting allocation data to correct for reverse flow caused by GXP ties. This is taken from clause 34(12) of the current TPM. Clause 34(12) of the current TPM, and clause 14(3) of the proposed TPM, includes an obligation to publish reverse flow adjustments. We propose to extend that to EOC adjustments as well (clause 15(2) of the proposed TPM).

12 Applications under the TPM

47. Clause 16 of the proposed TPM contains some general rules for applications under the TPM,[19] including a "first come, first served" rule, a right for Transpower to suspend or reject an application if it is non-compliant, and an obligation on Transpower to assess applications within a reasonable time.

48. Our proposal includes application fees and application content requirements, which must be reasonable and will be published on our website. This will provide flexibility to change these administrative matters without reopening the TPM (which is not a straightforward exercise under the Code).

49. At this stage we have not finalised any fees or fee structures for applications. This is something we will do between now and the start of the new TPM. However, we have allowed for a range of possibilities, including staged and refundable fees, in clause 16(3) of the proposed TPM. In any event, the fees must be reasonable having regard to our expected costs of assessing the applications.

---

[18] Reference document #3 2020 Decision: At paragraph 2.21 the Authority said *"while fairness is not expressly included as part of the Authority's statutory objective, the Authority has the long-term interests of consumers at the centre of its decision-making. Perceptions of unfairness can detract from the durability and associated regulatory certainty of the TPM, which may in turn affect the efficient operation of the industry."*

[19] Our proposal includes applications for prudent discounts and reassignment.

13 Consistency with the Guidelines

50. We consider our proposals for the matters covered in this chapter are fully compliant with the Guidelines. See the Guidelines compliance matrix attached to this paper.

Chapter 4: Part B – Grid Asset Classification

30 June 2021

Contents: Chapter 4

1 Introduction

1. This chapter summarises and explains our proposals for the grid asset classification provisions of the proposed new TPM.

2. The grid asset classification provisions are concerned with classifying grid assets as either connection or interconnection. The costs of connection assets, and transmission alternatives for them, are recovered through connection charges. The costs of interconnection assets, and transmission alternatives for them, are recovered through benefit-based charges (**BBCs**) and residual charges.

2 Requirements of the Guidelines

3. Consistent with the current TPM, the Guidelines contemplate grid assets being classified as either connection assets (providing transmission services to one or a few customers only) or interconnection assets (providing transmission services to many or all customers).[1]

> **connection assets** means the <u>assets</u> owned by <u>Transpower</u> used to connect a <u>designated transmission customer’s</u> plant to the **interconnected grid**, and may have a more precise definition in the **TPM** as amended from time to time.
>
> **connection investment** means an **investment** owned by <u>Transpower</u> used to connect a <u>designated transmission customer’s</u> plant to the **interconnected grid**, and may have a more precise definition in the **TPM** as amended from time to time.

[1] The current TPM treats the HVDC link as a separate asset class, which is not necessary under the new TPM because there will no longer be an HVDC charge. In the Guidelines and proposed TPM, the grid assets comprising the HVDC link are interconnection assets (definition of “interconnected grid” in the Guidelines and clause 23(2) of the proposed TPM).

interconnected grid means the elements of the grid owned by Transpower including the HVDC link but excluding **connection assets**.

interconnection assets means the assets which form part of the **interconnected grid**, and may have a more precise definition in the **TPM** as amended from time to time.

4. Clauses 11 and 12 of the Guidelines relate to grid asset classification.

   11. The **TPM** must provide for the costs of **connection investments** to be recovered from those designated transmission customers whose assets are connected to the assets forming part of those **connection investments**.

   12. 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.

5. As all grid assets are either connection or interconnection assets, clause 12 informs the definition of both classes of grid asset. Clauses 11 and 12 are close facsimile of clause 9 and 10 of the previous Guidelines, on which the grid asset classification clauses in the current TPM are based.[2]

6. Clauses (viii) and 54 to 56 of the Guidelines relate to additional components and are also relevant to grid asset classification.

Additional components

viii. Transpower must include each **additional component** in the **TPM** if doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**.

   a. Adjustments to charges for 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 as to not unreasonably deter staged commissioning of **investments**.

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

…

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. adjustments to charges for staged commissioning, as described in clause 55;

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

…

Additional component A: adjustments to charges for staged commissioning

55. This component must provide a method for Transpower, at its discretion, to adjust charges, change asset classification and/or use a hybrid asset classification so that in Transpower's reasonable opinion, the charges for a **connection asset** that will ultimately

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

be an **interconnection asset** do not unreasonably deter the partial commissioning of the asset. The **benefit-based charge** must apply when the assets meet the definition of **interconnection assets** and must recover the present value of the **covered cost** of the **investment**, less any **connection charges** paid for it.

Additional component B: charges for assets principally providing connection services

56. This component must provide a method to ensure that **connection assets** cannot be changed into **interconnection assets** by a person other than Transpower investing in other assets to create an interconnection loop.

7. We propose to implement additional components A and B, as discussed in Section 5.[3]

3 Stakeholder engagement and process

3.1 Consultation

8. In August 2020, we released a consultation paper seeking feedback on options for connection charges (our connection charges consultation paper), which included preliminary TPM drafting for grid asset classification.

9. Our connection charges consultation paper covered eight focus areas, including:

   9.1 classification of assets during staged commissioning (additional component A of the Guidelines); and

   9.2 effect of other parties connecting to grid assets (additional component B of the Guidelines).

10. Our connection charges consultation paper, submissions and cross-submissions are published on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[4]

11. We have taken the submissions and cross-submissions on our connection charges consultation paper into account in preparing the proposed TPM.

3.2 Checkpoint 2

12. In November 2020, we submitted our preliminary proposals for connection charges, including grid asset classification, to the Authority as part of its Checkpoint 2 process (our Checkpoint 2A submission).[5] The preliminary TPM drafting we submitted with our Checkpoint 2A submission included grid asset classification provisions similar to the equivalent provisions now in the proposed TPM. In its feedback on our Checkpoint 2A submission, the Authority confirmed our preliminary proposals were *"appropriate and largely consistent with the guidelines"* and *"we [the Authority] do not have any substantive concerns with the proposed TPM drafting with respect to the connection charge."*[6]

[3] Additional components C and F also relate to connection charges. We do not propose to implement those additional components at this time. This decision is discussed in Chapter 5 (Connection charges).

[4] TPM Development: Connection Charges consultation process

[5] Reference Document #31 Checkpoint 2 submission: Residual Charge and Transitional Cap.

[6] Reference document #35 Letter from EA: Checkpoint 2A submission.

13. In March 2021 and May 2021, we submitted further preliminary TPM drafting to the Authority as part of its Checkpoint 2 process (our Checkpoint 2B submission and resubmission).[7] The preliminary TPM drafting included substantially the same grid asset classification provisions as we had submitted with our Checkpoint 2A submission. In response to our Checkpoint 2B resubmission, the Authority provided some feedback on the preliminary TPM drafting.[8]

14. We have taken the Authority's feedback on our Checkpoint 2B submissions and resubmissions into account in preparing the proposed TPM.

4 Summary of our proposal

15. As we noted in our connection charges consultation paper:

> Our experience is that our customers are generally satisfied with the way connection charges work currently. Therefore, and being mindful of the harder work to come on other elements of the new TPM, the options presented in this consultation paper are for moderate and incremental changes.[9]

16. Many submitters on the connection charges consultation paper confirmed this supposition. Accordingly, we are not proposing to redesign grid asset classification in the new TPM. We propose the new TPM will continue to define connection and interconnection nodes, links and assets by reference to the physical configuration of the grid, with the distinguishing characteristic of interconnection nodes, links and assets being their existence in a loop of continuous nodes and links with the same start and end point (clauses 22 and 23 of the proposed TPM). The changes to grid asset classification we are proposing are moderate and incremental.

17. We consider this moderate and incremental approach is further supported by:

 17.1 the similarity between the clauses of the previous Guidelines and the new Guidelines relating to connection charges. In particular, both require connection assets to include "deep connection" assets, being connection assets that exist further into the grid than connection locations[10] (clause 24(5)(b) of the proposed TPM);

 17.2 the principle in clause 1(b)(iv) of the Guidelines. We do not consider the costs associated with changing fundamentally the way grid asset classification works are necessary given the level of satisfaction customers have with how it works currently; and

---

7 Reference document #52 Checkpoint 2B submission: preliminary TPM drafting and Reference document #64 Checkpoint 2B resubmission: preliminary TPM drafting

8 Reference document #69 Letter from EA: Checkpoint 2B resubmission Appendix E: comments on preliminary TPM drafting

9 Reference document #11 Connection charges consultation paper, paragraph 5

10 Authority, TPM options working paper: Companion paper describing the detail of the deeper connection charge, June 2015:
"*2.1 The current connection charge is a 'deep' connection charge as it includes both:*
(a) assets that provide a physical connection to the grid (which would be the only assets included in a 'shallow' connection definition) plus
(b) some assets beyond the point of physical connection that exist to physically connect parties' electrical assets to the grid. …
2.3 The Authority proposes to retain the existing connection charge."

17.3 the principles in clauses 1(b)(ii) and (iii) of the Guidelines, specifically simplicity and certainty in the transition to the new TPM.

18. We propose to maintain the status quo for grid asset classification, but with the following changes which are discussed in the following Sections:

18.1 **Classification of assets during staged commissioning (additional component A of the Guidelines):** Allow connection assets to be treated as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned.

18.2 **Effect of other parties connecting to grid assets (additional component B of the Guidelines):** Make future non-Transpower links "invisible" to the TPM unless Transpower agrees otherwise.

18.3 **Grid asset classification "safety valve":** Allow grid assets that would otherwise be interconnection assets to be classified, or prospectively reclassified, as connection assets if they are providing connection services in substance.

5 Additional components A and B

19. Under clause 54 of the Guidelines, we must propose to implement an additional component in the TPM if, in our reasonable opinion, we consider doing so would better meet the Authority's statutory objective than not implementing it.

5.1 Additional component A: Classification of grid assets during staged commissioning

20. We propose to implement additional component A. We consider implementing additional component A would better meet the efficiency limb of the Authority's statutory objective than not implementing it.

21. Additional component A is intended *"to address any inefficient incentives for a customer to seek to avoid staged commissioning."*[11] We consider situations may arise where staged commissioning of an interconnection investment will be efficient and should not be disincentivised by an interim connection classification. The North Auckland and Northland (**NAaN**) investment is a case on point, the staged commissioning of which precipitated litigation on the issue of interim grid asset classification.[12]

22. We propose to require connection assets to be treated as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned. We consider there needs to be a time limit to remove any inefficient incentives for a customer to avoid full commissioning of the asset indefinitely.

23. The proposed TPM implements additional component A in clause 22(4). Our proposed minimum time limit is nine months from when the first node or link in the relevant group of

[11] Reference document #3 2020 Decision, paragraph 14.7.

[12] *Vector Limited v Transpower New Zealand Limited and Electricity Authority* [2014] NZHC 3411. See paragraphs [31] and [39] as to the potential benefits, including efficiency benefits, of staged commissioning.

nodes and links is commissioned.[13] This is a minimum because the effective time limit is influenced by the need to align transmission charge changes with the start of a pricing year. We expect that most of the time the effective time limit will be longer than nine months (but it will never be shorter).

24. This proposal may result in a grid asset's classification, and therefore its basis for charging, changing from interconnection to connection and back to interconnection, depending on the timing gap between partial and full commissioning. We consider this is a better outcome than allowing a grid asset that is providing connection services to be classified as interconnection indefinitely. There will never be double-recovery of costs for the grid asset because it will be depreciating continuously and will never be a connection and interconnection asset at the same time.

5.2 Additional component B: Effect of other parties connecting to grid assets

25. We propose to implement additional component B. We consider implementing additional component B would better meet the efficiency limb of the Authority's statutory objective than not implementing it.

26. In its 2020 Decision the Authority said:

> Under [additional component B], interconnection assets that principally provide connection services would be charged for as if they were connection assets, even if they do not meet the technical definition of a connection asset. The aim was to address inefficient incentives for a customer to seek to have assets classified as interconnection assets. [14]

27. We have seen this happen when the HTI-TMU line was built by Waipa Networks connecting the substations at Hangatiki and Te Awamutu, creating an interconnection loop and thereby reclassifying former connection assets (KPO-TMU A and RTO-HTI A) as interconnection assets and socialising their costs. While we do not believe the HTI-TMU line was built for this purpose, it nevertheless had this effect and brought the issue to light. We consider socialising (through BBCs or residual charges) the costs of grid assets that perform the function of connection assets in these circumstances is potentially inefficient because it may reduce scrutiny of connection investments.[15]

28. We propose to make future non-Transpower links "invisible" to the TPM unless Transpower agrees otherwise (for example, because the non-Transpower link helps defer investment in some other part of the grid). This means the existence of such links cannot impact on the connection/interconnection classification of grid assets without Transpower's consent.

29. The proposed TPM implements additional component B in clauses 19(1) and 21(3), through the definition of "grid assets". We propose to expand on the definition of "grid assets" in the

---

[13] This is based on the period of time between partial and full commissioning of the NAaN investment. We have assumed this is a reasonable minimum time limit for the prospective classification of grid assets during staged commissioning.

[14] Reference document #3 2020 Decision, paragraph 14.11. See also Reference document #1 2019 issues paper, paragraphs B.294 to B.301.

[15] We do not consider socialising the costs of connection assets will be inefficient in all circumstances. Specifically, we consider socialising the cost of additional capacity in connection assets is an appropriate response to first mover disadvantage for connection investments. This is discussed in Chapter 5 (Connection charges).

current TPM to clarify that grid assets are limited to assets or other works[16] that comprise or support the grid and:

29.1 are owned by or leased to Transpower, and not leased or on-leased by Transpower to another person; or

29.2 Transpower has expressly agreed are to be treated as grid assets for the purposes of the TPM.

6 Grid asset classification "safety valve"

30. Clause (vii)(b) of the Guidelines says the purpose of additional component B is:

> to ensure that if a **connection asset** is reclassified as an **investment** in the **interconnected grid** but continues in substance to provide principally connection services, it is still charged for as a **connection asset**.

31. We consider this supports a more general approach in the new TPM to addressing situations where grid assets that technically meet the definition of interconnection assets are principally providing connection services in substance.

32. The definitions of connection and interconnection node, link and asset in the current and proposed TPM are necessarily general, and they may occasionally result in anomalous outcomes (outside of the specific situation contemplated in additional component B). We have recently discovered an example of this in the Buller region where an unusual grid configuration results in some grid assets supplying a single customer (i.e. assets in substance providing connection services) being classified as interconnection assets.

33. Clause 25 of the proposed TPM contains a discretion for Transpower to classify, or reclassify prospectively,[17] a grid asset that would otherwise be an interconnection asset as a connection asset if:

33.1 the grid asset provides connection services in substance (by reference to the number of customers served by the grid asset); and

33.2 we determine it is fair and reasonable in all the circumstances to classify or reclassify the grid asset as a connection asset.

34. We consider this proposal to be a reasonable implementation of clauses 11 and 12 of the Guidelines, informed by the stated purpose of additional component B.

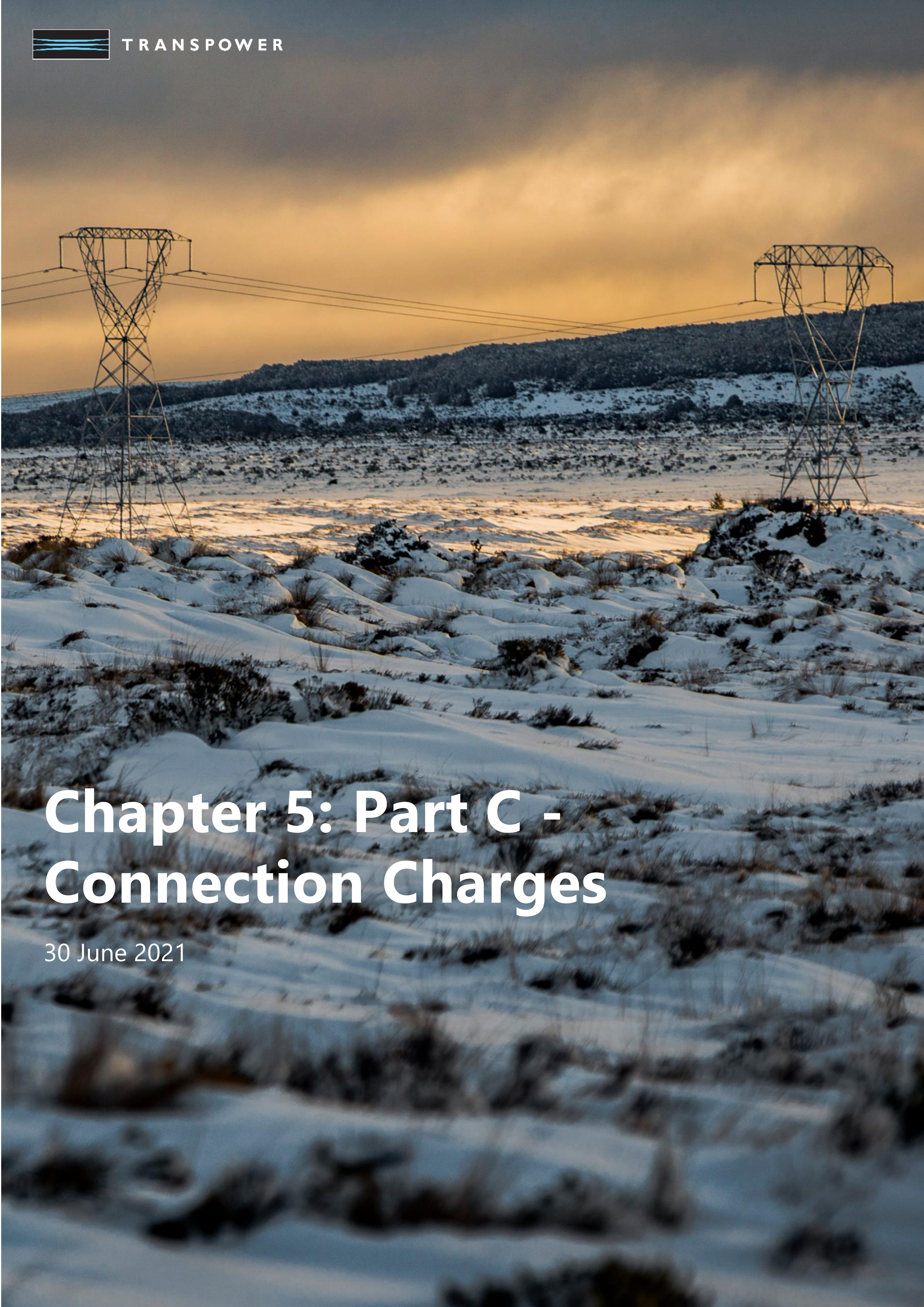
7 Consistency with the Guidelines

35. We consider our proposals for grid asset classification are fully compliant with the Guidelines. See the Guidelines compliance matrix attached to this paper.

[16] "Other works" include land, easements, leases and other interests in land, buildings, containment facilities and other structures that support the grid. These works do not fall within the definition of "asset" in the Code. This reflects the definition of "land and buildings" in the current TPM, which are deemed to be grid assets.

[17] We would not be able to reclassify, or adjust transmission charges to reflect the reclassification, retrospectively.

TRANSPOWER



Chapter 5: Part C - Connection Charges

30 June 2021

Contents: Chapter 5

1 Introduction

1. This chapter summarises and explains our proposals for the connection charges provisions of the proposed new TPM.
2. Connection charges recover the costs of connection investments (investments in connection assets and connection transmission alternatives).

2 Requirements of the Guidelines

3. Clause (iii) of the Guidelines states the purpose of connection charges.

> The purpose of the **connection charge** is to charge each designated transmission customer to recover the cost of the **connection investments** that connect that designated transmission customer's assets to the **interconnected grid**.

4. The connection charge is main component 1 of the Guidelines (clauses 11 and 12).

> **Main component 1: connection charge**
>
> 11. The **TPM** must provide for the costs of **connection investments** to be recovered from those designated transmission customers whose assets are connected to the assets forming part of those **connection investments**.

12. 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.

5. Clauses 11 and 12 are close facsimiles of clauses 9 and 10 of the previous TPM Guidelines, on which the current design of connection charges is based.[1]

6. Clauses (viii), 54, 57 and 64 of the Guidelines relate to additional components and are also relevant to connection charges.[2]

Additional components

viii. Transpower must include each **additional component** in the **TPM** if doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**.

...

c. Charges for **connection investments** to use a method substantially the same as for **benefit-based charges**. The purpose of this component is to allocate the charges for each **connection investment** in substantially the same way as the charges for each **benefit-based investment**.

...

f. Allocation of **opex**. The purpose of this component is to attribute **opex** to the **connection investment** or **benefit-based investment** that it is spent on without recourse to proxies.

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**:

...

c. charges for **connection investments** to use a method substantially the same as for **benefit-based charges**, as described in clause 57;

...

f. allocation of **opex**, as described in clause 64;

...

Additional component C: charges for connection investments to use a method substantially the same as for benefit-based charges

57. This component must provide for the method for determining the annual amount to be recovered for each new **connection investment** to align with the method for determining the **annual benefit-based charge** for **post-2019 benefit-based investments**, notwithstanding the requirements of clauses 11 and 12.

...

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

2 Additional components A and B also relate to connection charges. We propose to implement those additional components. This decision is discussed in Chapter 3 (Grid asset classification).

Additional component F: allocation of 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.

3 Stakeholder engagement and process

3.1 Consultation

7. In August 2020, we released a consultation paper seeking feedback on options for connection charges (our connection charges consultation paper), which included preliminary TPM drafting.

8. Our connection charges consultation paper covered the following focus areas:

   8.1 TPM drafting tidy-up – see Chapter 2 (Preliminary);

   8.2 classification of assets during staged commissioning (additional component A of the Guidelines) – see Chapter 4 (Grid asset classification);

   8.3 effect of other parties connecting to grid assets (additional component B of the Guidelines) – see Chapter 4 (Grid asset classification);

   8.4 regular updating of connection asset replacement costs;

   8.5 introduction of cable line type for maintenance costs;

   8.6 investment contract arrangements;

   8.7 connection asset decommissioning costs; and

   8.8 first mover disadvantage (**FMD**) for connection investments.

9. The connection charges consultation paper, submissions and cross-submissions are published on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[3]

10. In October 2020, we released a consultation paper seeking further feedback on the extent to which FMD might be a problem and how (and whether) it could be addressed in the new TPM (our FMD consultation paper).

11. Our FMD consultation paper covered the following focus areas:

    11.1 "Type 1" FMD for connection investments. Type 1 FMD is a free rider problem. Currently, a customer who funds the capital cost of a connection asset under an investment contract does not get a contribution to that cost even if other customers later connect to the asset.[4]

    11.2 "Type 2" FMD for connection investments. Type 2 FMD is a potential efficiency problem. A prudent and efficient grid investment by Transpower, made in the

[3] TPM Development: Connection Charges consultation process

[4] In practice, we consider Type 1 FMD to be a problem for connection investments only. Interconnection investments are very rarely funded under investment contracts.

expectation of future generation or load development, may exceed the capacity requirements of the first or early customers who pay for the full capacity of the grid investment. This may deter the generation or load development the grid investment is designed to facilitate; and

11.3 Type 2 FMD for interconnection investments.

12. The FMD consultation paper, submissions and cross-submissions are published on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[5]

13. After considering stakeholder responses to our FMD consultation paper, we formed the view we cannot propose an additional method to address Type 2 FMD for interconnection investments because neither the Guidelines nor the Authority's intent supports such a method. This remains our view. The proposed TPM does not contain a method to address Type 2 FMD for interconnection investments beyond reassignment.

14. We have taken the submissions and cross-submissions on our connection charges and FMD consultation papers into account in preparing the proposed TPM.

3.2 Checkpoint 2

15. In November 2020, we submitted our preliminary proposals for connection charges to the Authority as part of its Checkpoint 2 process (our Checkpoint 2A submission).[6] In its feedback on our Checkpoint 2A submission, the Authority confirmed our preliminary proposals were *"constructive and useful and we [the Authority] are comfortable they are on track to align with the guidelines."*[7] The Authority provided feedback on some technical matters, including that the injection overhead component of the connection charge (a feature of the current TPM) *"appears to be inconsistent with the guidelines, which require that overhead costs are recovered through the residual charge."*

16. At the time of our Checkpoint 2A submission we were consulting further on options for addressing FMD. In March 2021, we submitted our preliminary proposals for FMD to the Authority as part of its Checkpoint 2 process (our Checkpoint 2B submission).[8] The Authority required us to resubmit some of our preliminary proposals for FMD,[9] which we did in May 2021 (our Checkpoint 2B resubmission).[10]

17. In its feedback on our Checkpoint 2B submission, the Authority said:

> The Authority is comfortable with Transpower's proposal for side payments to address free rider issues for the Type 1 FMD for connection assets, and with the proposal not to make specific changes to the benefit-based charge provisions to address [Type 2] FMD for interconnection assets.

[5] TPM Development: First Mover Disadvantage consultation process
[6] Reference document #30 Checkpoint 2 Submission: Connection Charge
[7] Reference document #35 Letter from EA: Checkpoint 2A submission
[8] Reference document #50 Checkpoint 2B submission: First Mover Disadvantage
[9] Reference document #56 Letter from EA: Checkpoint 2B submission
[10] Reference document #62 Checkpoint 2B resubmission: First Mover Disadvantage

> The Authority holds concerns about the proposed method to address Type 2 FMD for connection assets: to fund a connection asset's 'future-proofing excess capacity' via a surcharge on all customers.

18. The Authority reiterated its concerns about our preliminary proposals to address Type 2 FMD for connection investments in its response to our Checkpoint 2B resubmission:

> Transpower's re-submission for FMD type 2 for connection investments is unchanged from the submission's proposal: to socialise the cost of any additional capacity across all connecting parties. Our feedback on this matter remains consistent with that given on the Checkpoint 2b submission.
>
> The Authority agrees that efficient investments in connection capacity for new generation or electrification of load should not be discouraged by requiring all the costs of excess connection capacity to fall on first movers. We remain concerned though that socialising the costs of additional capacity could mean connecting parties have little incentive to scrutinise investment proposals and could risk inefficient overbuilding and higher electricity prices. We are aware that Transpower considers this to be low risk, but invite Transpower to consider any concrete steps and practical safeguards it could put in place to address this risk and limit its extent.

19. We have taken the Authority's feedback on our Checkpoint 2 submissions and resubmissions into account in preparing the proposed TPM. The Authority's specific feedback about Type 2 FMD is addressed in Section 10.2.

4 Summary of our proposal

20. As we noted in our connection charges consultation paper:

> Our experience is that our customers are generally satisfied with the way connection charges work currently. Therefore, and being mindful of the harder work to come on other elements of the new TPM, the options presented in this consultation paper are for moderate and incremental changes. The exception are options we are considering addressing the "first mover disadvantage" for connection investments, which would be a more material departure from current arrangements.

21. Many submitters on the connection charges consultation paper confirmed this supposition. Accordingly, we are not proposing to redesign the connection charge in the new TPM. The changes to connection charges we are proposing are moderate and incremental. Limited or no changes are needed to the substance of the connection charge provisions in the current TPM to comply with the Guidelines.

22. We consider the moderate and incremental approach we have taken is further supported by:

    22.1 the principle in clause 1(b)(iv) of the Guidelines. We do not consider the costs associated with changing fundamentally the way connection charges work are justified given the level of satisfaction customers have with how they work currently; and

    22.2 the principles in clauses 1(b)(ii) and (iii) of the Guidelines, specifically simplicity and certainty in the transition to the new TPM.

23. We propose to maintain the status quo for connection charges, but with the following changes which are discussed in the following Sections:

    23.1 **Removing the injection overhead component of connection charges:** Remove the injection overhead component. This is a consequence of our proposal for allocating overhead costs to benefit-based investments (**BBIs**).

    23.2 **Regular updating of connection asset replacement costs:** Update the connection asset replacement costs we use to calculate connection charges at intervals of no more than 5 years.

    23.3 **Introduction of (underground) cable line type for maintenance costs:** Introduce a cable line type and allow Transpower to estimate the maintenance recovery rate until there is a sufficient history of maintenance costs for connection asset cables.

    23.4 **Allowing partial contributions in Investment contracts:** Allow for partial capital contributions to connection investments under investment contracts and contributions to connection maintenance and operating costs under investment contracts.

    23.5 **Addressing FMD for connection investments:** Introduce a funded asset component of connection charges, and associated funded asset rebates, to address Type 1 FMD, and address Type 2 FMD by allowing Transpower to use a discounted replacement cost to calculate the asset component of connection charges.

24. We do not propose to make any changes to the current arrangements for recovering connection asset decommissioning costs, and we do not propose to implement additional components C and F. This is discussed in Sections 9 and 11.

5 Injection overhead component

25. Connection charges in the current TPM include an injection overhead (**IOH**) component, which is charged only to injection customers. Clause 21 of the current TPM explains the reason for the IOH component.

    > **Offtake customers** pay a portion of **AC revenue** overhead costs through the interconnection charge. **Injection customers** are not charged an interconnection charge, so a share of **AC revenue** overhead cost is allocated through their **connection** charges.

26. Our preliminary proposal was to continue the IOH component in the new TPM, consistent with our general approach of not disrupting current connection charges arrangements unnecessarily and because, under the Guidelines, customers do not pay residual charges based on their injection.

27. Also, and importantly, we do not agree with the Authority's view, expressed in its feedback on our Checkpoint 2A submission, that the Guidelines "*require that overhead costs are recovered through the residual charge.*" The Guidelines do not say that or, in our view, imply it. Clause 27 of the Guidelines says the residual charge is to allow

recovery of any remaining recoverable revenue not otherwise recovered through other transmission charges. In meetings between Transpower and Authority staff, and in the Authority's feedback on our Checkpoint 2B submission, the Authority suggested the reference in clause 6 of the Guidelines to the residual charge potentially comprising *"unallocated opex"* means overhead costs must be allocated to the residual. We disagree. In our view, *"unallocated opex"* in clause 6 simply means opex not allocated to other charges, whatever its nature (overhead or otherwise), consistent with clause 27. In addition, clause 6 is a notification requirement and does not directly relate to how costs are allocated to different transmission charges.

28. Part of our wider proposal is to allocate part of our total overhead costs (meaning network and non-network costs not directly attributable to a particular investment) to BBIs and recover that part of our costs through benefit-based charges (**BBCs**) (see Chapter 6 (Covered cost)). That proposal takes away the case for retaining the IOH component because all customers will pay BBCs, including based on their injection.

29. In other words, we think there should be one or the other, and our decision in the proposed TPM is to attribute part of our total overhead costs (network and non-network) to BBIs and not include an IOH component. However, we are aware the Authority has reservations about attributing overhead costs to BBIs. We consider that if our proposal for attributing overhead costs to BBIs is not implemented in the new TPM, the new TPM should include the IOH component. To inform the Authority and show how the IOH component would work, we have included drafting for the IOH component in the proposed TPM (the relevant provisions highlighted in grey, principally clause 32).

6 Regular updating of connection asset replacement costs

30. Connection asset replacement costs are used to calculate the asset, maintenance and IOH components of connection charges (clauses 27, 30 and 32 of the proposed TPM).

31. Most of the replacement costs we use to calculate connection charges have not been updated for many years and the relativities between them (which is what counts in terms of calculating connection charges) may no longer be accurate.

32. Clause 35 of the proposed TPM requires us to update the connection asset replacement costs at intervals of no more than five years, with the first such update to happen within 5 pricing years of the effective date of the new TPM. We may update the connection asset replacement costs before the effective date of the new TPM. We may update the connection asset replacement costs more frequently than every five years, for example if our assessment of a reassignment or stand-alone cost prudent discount application results in new or updated replacement cost information.

33. We must consult before we update the replacement costs unless Transpower reasonably considers the update to be technical and non-controversial, there is widespread support for the update amongst customers, or there has been adequate prior consultation (echoing the exceptions to consultation in section 39(3) of the Electricity Industry Act 2010).

7 Introduction of cable line type for maintenance costs

34. We propose to introduce a cable line type for calculating the maintenance component of connection charges (clause 30(5)(d) of the proposed TPM).

35. The line maintenance cost component for a line connection asset depends on the length of the line and its line type (clauses 30(6) and (7) of the proposed TPM). Currently, cables are not recognised as a line type and so do not attract a maintenance component. In practice, this is not currently a problem because there are currently no connection asset cables.

36. We propose to estimate the maintenance recovery rate for connection asset cables until we determine there is a sufficient history of maintenance costs for connection asset cables for the rate to be calculated (clauses 30(7) and (8) of the proposed TPM]).

8 Investment contract arrangements

37. We propose to allow for partial capital contributions to connection investments under investment contracts and contributions to connection maintenance and operating costs under investment contracts (clauses 20, 30(1) and 31(1) of the proposed TPM). The current TPM does not expressly provide for either of these things, creating the potential for under-recovery (in the case of partial capital contributions) and over-recovery (in the case of contributions to maintenance and operating costs).

38. The capital contribution part of our proposal is implemented in clause 20 of the proposed TPM by allowing for a single physical connection asset, the capital cost of which is partially funded by a customer or other person under an investment contract, to be treated as multiple grid assets (funded and non-funded). This mechanism is also potentially relevant to partial funding of the capital cost of interconnection assets.

9 Connection asset decommissioning costs

39. In our connection charges consultation paper, we proposed allocating the decommissioning costs for connection assets to the customer(s) connected to the assets when they are decommissioned.[11]

40. Several submitters expressed concerns about connection asset decommissioning costs being a function of historic capacity requirements and potential unfairness for the "last man standing" if the decommissioning costs are allocated to them.[12]

41. Having considered those submissions, we have decided not to propose a mechanism for allocating connection asset decommissioning costs to those customers connected to the connection assets when they are decommissioned. The effect is that connection asset decommissioning costs will be allocated to load customers through their residual

[11] Reference document #11 Connection Charges consultation paper, focus area 7.
[12] TPM Development: Connection charges consultation process

charges under the new TPM. This treatment is consistent with how connection asset decommissioning costs are allocated under the current TPM, i.e. to offtake customers through their interconnection charges.

10 First mover disadvantage

10.1 Type 1 FMD for connection investments

42. We propose to address Type 1 FMD for connection investments using a funded asset component (**FAC**) mechanism (clauses 28 and 29 of the proposed TPM).

43. The mechanism would work by collecting, via connection charges, a financial contribution to the capital cost of a connection investment funded by a first mover customer under an investment contract from later customers (the FAC) and rebating it to the first mover customer (even if the investment contract has expired). This approach uses connection charges to simulate a commercial outcome the first mover and subsequent customers might reasonably have agreed had they had the opportunity to do so at the time the first mover entered into the investment contract. Our proposal assumes 10 years is a reasonable payment period, which is based on the maximum payment period we may be prepared to agree to in an investment contract.

44. The FAC would be $0 for all connection assets other than those that were funded or part-funded by a customer under an investment contract. For a connection investment that was funded or part funded by a customer under an investment contract, the FAC would re-balance connection charges between the first mover and subsequent customers.

45. We have reproduced below the simplified worked example from our Checkpoint 2 submission for FMD.[13]

- Customer C1 (the first mover) funds 100% of the capital cost of a connection asset under an investment contract. Suppose the annual new investment charge (NIC) under the investment contract is a flat $100 per year. Sometime after the asset is commissioned, customer C2 connects to it at the same connection location as C1.
- At that time C2's gross annual contribution to the capital cost is calculated by reducing the total NIC paid (or to be paid) by C1 in proportion to the remaining economic life of the asset and dividing by 10 (representing a 10-year payment period). Suppose this works out to be $45 per year, which is C2's funded asset component (FAC) of its connection charge for the asset.
- C2's FAC ($45) is then adjusted for C2's allocation of the asset at the connection location (suppose 40%, based on each customer's AMDC/AMIC). The adjusted amount is then rebated to C1 through a reduction in C1's transmission charges. The result is this:

	NIC contribution	FAC (gross annual contribution)	Customer allocation	Adjusted annual contribution/rebate
C1	100	0	0.6	-18

[13] Reference document #50 Checkpoint 2B submission: First Mover Disadvantage, page 8.

C2	0	45	0.4	45 x 0.4 = 18

- After 10 years C2's contribution would end, as would C1's rebate.
- Suppose, before C2's contribution ends, customer C3 connects to the asset at the connection location and the same calculation as above produces an FAC for C3 of $20. Assuming the customer allocations are as below, and rebating to C1 and C2 in proportion to their customer allocations, the result is this:

	NIC contribution	FAC (gross annual contribution)	Customer allocation	Adjusted annual contribution/rebate
C1	100	0	0.5	-18 – 2.5 = -20.5
C2	0	45	0.3	18 – 1.5 = 16.5
C3	0	20	0.2	20 x 0.2 = 4

46. There was general support for this proposal from all submitters[14] on our FMD consultation paper, except MEUG (who questioned the need to address FMD at all, rather than the FAC proposal itself) and Vector (who didn't express a position).

47. In response to MEUG's point, even if Type 1 (or Type 2) FMD is not currently a material problem, it may be in the future. We consider now is an opportune time to include mechanisms in the TPM to address FMD, to the extent we can. This is the least regrets option with little or no downside.

48. We are mindful of the issues that may arise from decarbonisation and the future electrification of load, in particular. We consider it is important the TPM provides a transparent and robust solution for Type 1 FMD now. Stakeholders need to know how the issue will be resolved to support their investment decisions.

10.2 Type 2 FMD for connection investments

49. We propose to address Type 2 FMD for connection investments through the asset component of connection charges (clauses 27 of the proposed TPM).

50. Absent an explicit solution for Type 2 MFD for connection investments, the implicit outcome will be recovery via the 'EV account' washup mechanism in our IPP. This mechanism ensures Transpower is, over time, able to recover any cost of 'X 'that is not recoverable as connection charges in a particular pricing year (less any incentive penalty arising from overspendings against of our capex allowance). The effect will be to recover any otherwise allowable and unrecovered costs of 'X' from load customers as residual charges commencing from the beginning of the subsequent RCP.

51. In summary, we propose:

    51.1 For the purposes of calculating the asset component of the connection charge for a connection asset with additional capacity, we will reduce the replacement cost of the connection asset so that it matches the replacement cost of an asset with the capacity the existing customer(s) need (clause 27(2) of the proposed TPM). That is, we will base the replacement cost on a capacity of C rather than

14 TPM Development: First Mover Disadvantage consultation process

C+X. A factor relevant to determining the amount of additional capacity will be the capacity the relevant customer(s) have agreed to fund under investment contracts.

51.2 The part of the asset component of the connection charge for the discounted connection asset that is attributable to the additional capacity (X) will be allocated to other connection assets (including investment contract assets) in proportion to their replacement costs (clauses 27(1) and (4) of the proposed TPM). The result is some (or potentially all) of the asset component will be recovered from all customers paying connection charges (which is to say, all customers). We have considered the option of recovering the cost of the additional capacity through residual charges. We do not prefer that approach because a solution to Type 2 FMD is as likely to deliver connection capacity for new generation as it is for the electrification of load, and only load customers pay residual charges. Related to this point, as we noted in our Checkpoint 2B resubmission:[15]

> 12. We do not agree customers not currently connected to the connection investment would not benefit from the additional capacity. The additional capacity would provide optionality benefits for those customers. Due to the economics of grid investment, it may well be more expensive for a customer to pay to upgrade the connection investment with additional capacity when required than pay a (widely distributed) part of the cost of additional capacity that is ready to go. It would almost certainly be more expensive overall to build connection investments in that way (i.e. through a series of "just in time" upgrades), and therefore inefficient overall.

51.3 To avoid retrospectivity in the new TPM, this mechanism will only apply to new connection assets, i.e. those commissioned after the effective date of the new TPM (clause 27(2)(a) of the proposed TPM).

52. This proposal is similar to reassignment for BBIs. As with reassignment, the result is the risk of an "over-sized" investment is spread over a large number of customers (not just a few).

53. Other similarities with reassignment are that there will be no time limit on the replacement cost discount and the cost of the additional capacity will not be "paid back" after the investment is more fully utilised. If potential new entrants know there is a time limit unrelated to capacity use or a future pay-back obligation, that will impact on their decisions to enter or not. We therefore consider a time limit or pay-back mechanism would risk undermining one of the purposes of addressing Type 2 FMD, which is to remove disincentives to connect to new connection investments early. In addition, a pay-back obligation could create a perverse price signal for later entrants. Later entrants might be incentivised to connect to the grid, or embed, in a way that avoids the pay back obligation but is costlier overall because it does not take advantage of the existing additional capacity (which may have been built with later entrants in mind).

[15] Reference document #62 Checkpoint 2B resubmission: First Mover Disadvantage, page 5

54. There was minority support for addressing Type 2 FMD from submitters on our FMD consultation paper. Most submitters either said we should not attempt to address type 2 FMD or proposed options outside of the scope of the TPM. Our proposal remains to take this opportunity to address Type 2 FMD for connection investments, in the way outlined above. We can see how Type 2 FMD for connection investments could become a material problem, especially with accelerated electrification and renewables development. Now is the right time to address the potential problem, to the extent the TPM can, through measured, moderate reform of the connection charges methodology.

55. Some submitters considered we should "take the risk" of initially over-sized investments. Our regulation under Part 4 of the Commerce Act 1986 currently puts investment risk on consumers, with the safeguard of Commerce Commission scrutiny before the investment is made. The quid pro quo of this arrangement for consumers is that Transpower receives a lower regulated WACC and transmission charges are lower overall. Suggestions that Transpower take on additional investment risk not contemplated by our Part 4 regulation, for no additional compensation, would result in an expected shortfall for Transpower. We cannot propose any mechanism that compromises our ability to obtain a commercial return on our prudent and efficient investments. To do so would be inconsistent with the purpose of the TPM, which, under clause 12.78 of the Code is *"to ensure, subject to Part 4 of the Commerce Act 1986, the full economic costs of Transpower's services are allocated."*

56. We have considered the various options suggested by the Authority in its feedback on our Checkpoint 2 submission. For the reasons in paragraphs 15 to 35 of our Checkpoint 2 resubmission,[16] we have not proposed any of those options.

57. We have considered measures to protect against the risk of our proposal causing inefficiency by reducing incentives for customers to scrutinise connection investment proposals (as the Authority invited us to do in its feedback on our Checkpoint 2B resubmission).[17] We understand the Authority is alluding to something along the lines of the stand-down period that applies to reassignment under clause 35(b)(ii) of the Guidelines. As with the time limit and pay-back options, we consider such a mechanism would risk (in this case, very directly) undermining the purpose of addressing Type 2 FMD, which is to remove disincentives to connect to new connection investments early. In any event, as we said in our Checkpoint 2B resubmission:

> 10. We do not agree our preliminary proposal is likely to result in inefficient connection investments due to reduced investment scrutiny. We consider it is more likely there will be added scrutiny because a wide group of customers will bear part of the cost of the investment from day one (not just the first mover). Those customers or prospective customers with development plans that may involve connection to the investment in future will have an added incentive to scrutinise the investment because they know they will bear part of the cost of the investment, in the normal way, if they connect to it.
>
> 11. Even if there were an adverse impact on efficiency due to reduced scrutiny for a particular connection investment, in our view that reduction is likely to be

[16] Reference document #62 Checkpoint 2B resubmission: First Mover Disadvantage

[17] Document reference #67 Letter from EA: Checkpoint 2B resubmission, page 2

more than offset by overall efficiency gains from facilitating investment in efficient additional connection capacity while not discouraging connections (including to electrify process heat, and for future renewable generation that will compete in electricity, ancillary service and other markets).

58. We have reconsidered the question of whether our proposal for addressing Type 2 FMD for connection investments would be a departure from the requirements of clause 11 of the Guidelines. We now consider it would be a departure because some of the cost of the connection investment would be recovered from customers not connected to the grid assets comprised in the investment. This is discussed further in Section 12.

11 Additional components C and F

59. Under clause 54 of the Guidelines, we must propose to implement an additional component in the TPM if, in our reasonable opinion, we consider doing so would better meet the Authority's statutory objective than not implementing it.

11.1 Additional component C

60. We are not proposing to implement additional component C: charges for connection investments to use a method substantially the same as for benefit-based charges. We have not come to the reasonable opinion that implementing additional component C would better meet any of the limbs of the Authority's statutory objective than not implementing it.

61. Additional component C exists:[18]

> to address inefficient incentives for a customer to seek to have assets configured as either connection or interconnection assets, depending on whether the method for calculation of the connection charge or benefit-based charge was more advantageous to them.

62. Currently, connection and interconnection charges are calculated in different ways, with the latter very significantly more socialised. Despite that, we have not observed significant attempts by customers to manipulate grid configurations to avoid connection charges.[19] This reflects the way connection and interconnection nodes, links and assets are defined in the Code, which provides limited opportunity for avoidance behaviour and which we are not proposing to change fundamentally in the new TPM. We do not consider having different charging regimes for connection and interconnection investments is a material *"boundary issue"*.[20]

63. Further, we consider the current design of connection charges to already be benefit-based to a large degree because they are paid only by customers connected to the relevant connection investments, i.e. the direct and principal beneficiaries (the users) of connection investments pay for them. The Authority agreed with this proposition in paragraph C.25(a) of its feedback on our Checkpoint 2B resubmission.

---

[18] Document reference #3 2020 Decision, paragraph 14.14.

[19] We have proposed some tweaks to the grid asset classification rules that will remove opportunities for such manipulation, to the extent they exist. See Chapter 4 (Grid Asset Classification).

[20] Document reference #3 2020 Decision paragraph 14.16.

64. In terms of the efficiency limb of the Authority's statutory objective, to the extent there may be efficiency gains in moving to a different type of benefit-based charging regime for some connection investments, we do not consider those gains would justify the administrative costs of making the change.

65. Some other factors supporting our decision not to propose to implement additional component C are as follows:

    65.1 No submitter on our connection charges consultation paper advocated for additional component C to be implemented, on the basis of the Authority's statutory objective or otherwise.

    65.2 We consider achieving *"align[ment] with the method for determining the annual benefit-based charge for post-2019 benefit-based investments"* would involve a significant move away from the current design of connection charges. As noted above, the feedback we received on our connection charges consultation paper established that stakeholders are generally satisfied with the way connection charges currently work. The matters discussed in paragraph 22 are also relevant.

    65.3 If additional component C were implemented, it would mean connection charges for existing connection investments would be calculated on a different basis than connection charges for new connection investments (additional component C only applies to *"new connection investments"*). As well as introducing an additional layer of complication into transmission charges, this different treatment would discriminate arbitrarily between existing and new customers and could result in inefficient incentives when new customers are deciding where to connect to the grid. This is contrary to the principles in clauses 1(c) and (e) of the Guidelines.

66. The Authority requested we consider additional component C as an option for addressing FMD for connection investments, as part of our Checkpoint 2 resubmission. The Authority suggested Transpower could identify a group of benefitting customers using a method substantially the same as for benefit-based investments (this group being wider than the connected customer(s), but not as wide as all customers) and allocate the costs of the additional connection capacity to that group of customers. There are two significant problems with this suggestion:

    66.1 The arrangements would need to apply to *"each new connection investment"*, not just connection investments where Type 2 FMD is an issue. We do not consider a change of this magnitude is justified to address Type 2 FMD for connection investments when more moderate, targeted options are available (such as the one we have proposed).

    66.2 More fundamentally, additional component C does not speak to how connection charges are allocated, but rather to *"the annual amount to be recovered"*. In our view, additional component C is about importing the covered cost concept for BBIs to connection charges, not the methods for allocating BBCs.

11.2 Additional component F

67. We are not proposing to implement additional component F: allocation of opex. We have not come to the reasonable opinion that implementing additional component F would better meet the Authority's statutory objective than not implementing it.

68. At paragraph 14.35 of its 2020 Decision, the Authority said additional component F is designed to, potentially at least, "*promote efficiency*". We consider the practical difficulties, and associated expense, of directly attributing all opex categories to connection investments, to the extent it would even be possible to do so, would not be justified by any efficiency gains, especially against the counter-factual of our proposal to continue the current arrangements for attributing opex to connection investments. The Authority appeared to agree with this view, in the context of BBIs, in paragraph C.18 of its feedback on our Checkpoint 2B submission:

> We agree with Transpower that a highly granular approach to direct cost attribution is not required by the main components of the guidelines and agree Transpower's rationale (at para 16 of its 2b submission) for not adopting additional component F appears sound.[21]

69. Some other factors supporting our decision not to propose to implement additional component F are as follows:

    69.1 No submitter on our connection charges consultation paper advocated for additional component F to be implemented, on the basis of the Authority's statutory objective or otherwise.

    69.2 As noted above, the feedback we received on our connection charges consultation paper established that stakeholders are generally satisfied with the way connection charges work now. The matters discussed in paragraph 22 are also relevant.

12 Consistency with the Guidelines

70. Except for the matter discussed below, we consider our proposals for connection charges are fully compliant with the Guidelines. See the Guidelines compliance matrix attached to this paper.

12.1 Type 2 FMD for connection investments

71. As noted above, we consider our proposal for addressing Type 2 FMD for connection investments to be a departure from the requirements of clause 11 of the Guidelines.

72. We consider this departure is justified under clause 2 of the Guidelines.

    72.1 We consider the departure is not inconsistent with the intent of the Guidelines. Although the Guidelines do not contain express provisions dealing with FMD, the

[21] Reference document #67 Letter from EA: Checkpoint 2B resubmission Appendix A-D, paragraph C18.

Authority's 2020 Decision is clear the Authority did not intend to prevent FMD, including Type 2 FMD, being addressed in the TPM:

> 8.6 We recognise inefficient grid use arrangements are a risk of the first mover issue. But in discussions with Transpower on this issue, it was recognised this issue can be dealt with under the 2020 guidelines without introducing a new charge, as the broad language of the guidelines allows discretion in the way connection charges are set.
>
> 8.7 The Authority therefore considers the first mover issue is better addressed by Transpower (either through the TPM or via commercial negotiation), rather than by introducing specific provisions to address it into the TPM guidelines (such as introducing a new charge), as Transpower has the incentive and ability to address the issue and has relevant operational experience.[22]

72.2 We also consider our proposal is consistent with the principle in 1(c) of the Guidelines ("*avoid creating incentives for existing and potential designated transmission customers to avoid* ***transmission charges*** *in ways that cause economic inefficiency*") and in 1(f) ("*allow Transpower to recover up to, but no more than, its* ***recoverable revenue*** *should it wish to do so*").

72.3 We consider the departure promotes all three limbs of the Authority's statutory objective:

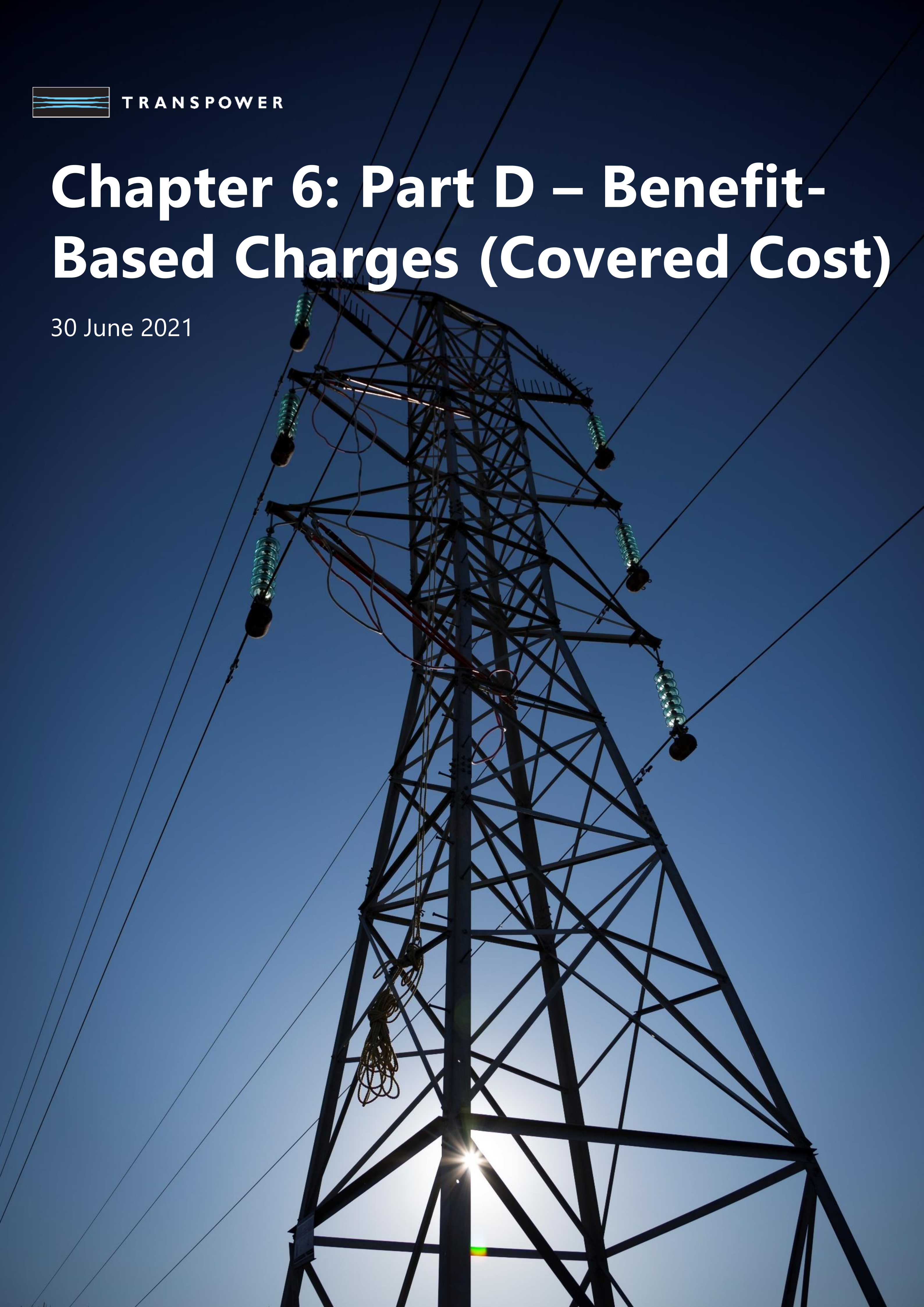
- Our proposal addresses the risk that first or early moving customers will be incentivised not to connect to new connection investments that have been built with additional capacity to accommodate future development. In so far as Type 2 FMD may deter future generation development, competition in wholesale electricity markets would be adversely affected. Similarly, reliability would be adversely affected because there would be less generation capacity to cover planned and unplanned events in the power system.
- Type 2 FMD may incentivise inefficient locational connection decisions for new generation and load. Customers or potential customers may choose grid or embedded points of connection that reduce their private costs, by avoiding the cost of additional connection capacity, while being costlier overall. As discussed above, we do not expect our proposal for addressing Type 2 FMD for connection investments will result in reduced scrutiny of connection investment proposals and, in any event, we consider efficiencies associated with provisioning for the future will outweigh any inefficiencies arising from reduced scrutiny.

22 Document reference #3 2020 Decision paragraph 8.6 and 8.7

TRANSPOWER

Chapter 6: Part D – Benefit-Based Charges (Covered Cost)

30 June 2021



Contents: Chapter 6

1 Introduction

1. This chapter summarises and explains our proposals for the covered cost provisions of the proposed new TPM.
2. The covered cost of a benefit-based investment (**BBI**) is the total amount that will be recovered through benefit-based charges (**BBCs**) for the BBI. A BBI's covered cost comprises:
   2.1 a return of capital (depreciation);
   2.2 a return on capital (capital charge);
   2.3 opex that is reasonable attributable to the BBI; and
   2.4 any other costs that are attributable to the BBI.

2 Requirements of the Guidelines

3. The benefit-based charge is main component 2 of the Guidelines. Clauses 15 to 17 relate to covered cost.

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

   15. Except as provided for in clause 16, 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 **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 **opex** reasonably attributable to the **benefit-based investment** based on an allocation of the **opex** allowance for the **pricing year** as set in the **IPP**; and

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

16. The **benefit-based charge** must recover the full present value of the **covered cost** of a **benefit-based investment** except where and to the extent that:

a. the **annual benefit-based charges** are adjusted or ended under clause 32 because the **benefit-based investment** is substantially damaged or destroyed;

b. that **benefit-based investment** is subject to **reassignment** in accordance with clauses 34 to 40;

c. the **benefit-based charge** has been scaled back in accordance with clauses 43 and 44; or

d. part of the **covered cost** is recovered through the **connection charge** as a consequence of the implementation of **Additional Component** A: adjustments to charges for staged commissioning.

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

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

4. Clauses (viii), 54 and 64 of the Guidelines relate to additional components and are also relevant to covered cost.

Additional components

viii. Transpower must include each **additional component** in the **TPM** if doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**.

...

f. Allocation of **opex**. The purpose of this component is to attribute **opex** to the **connection investment** or **benefit-based investment** that it is spent on without recourse to proxies.

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**:

...

f. allocation of **opex**, as described in clause 64;

...

Additional component F: allocation of 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.

3 Stakeholder engagement and process

3.1 Consultation

5. We did not consult on options for covered cost. The Guidelines are prescriptive about the components of covered cost, so there is limited scope for us to consider different options. We chose to focus our stakeholder engagement on other matters, including options for BBC allocation and adjustments.

3.2 Checkpoint 2

6. In March 2021, we submitted our preliminary proposals for covered cost to the Authority as part of its Checkpoint 2 process (our Checkpoint 2B submission).[1] Our Checkpoint 2B submission included preliminary TPM drafting for covered cost.[2]

7. In its feedback on our Checkpoint 2B submission, the Authority said it considered our preliminary proposals for covered cost were *"overall well-developed and largely consistent with the guidelines."*[3] The Authority asked us to resubmit our preliminary proposals in relation to:

    7.1 allocating overhead opex to BBIs; and

    7.2 the treatment of opex relating to fully depreciated assets that remain used and useful.

8. We resubmitted our preliminary proposals for covered cost to the Authority in May 2021 (our Checkpoint 2B resubmission).[4] In response to our Checkpoint 2B resubmission, the Authority commented:[5]

> We continue to consider that the preliminary proposal on covered costs is largely consistent with the guidelines. However, in our view the approach to the allocation of overheads still requires further consideration. We recognise that overheads are a material cost and the treatment of these costs under the proposed TPM requires careful consideration.

9. The Authority went on to say in paragraph C.7 of its feedback

> In summary, we consider that:
>
> (a) direct opex and shared direct opex are most likely reasonably attributable to a BBI under clause 15(c) of the guidelines
>
> (b) shared opex (overhead opex) requires judgement in applying the guidelines; at this time we have not yet settled on our view as to whether overhead opex is:
>
> (i) reasonably attributable to BBIs under clause 15(c) of the guidelines; or

1 Reference document #49 Checkpoint 2B submission: BBC Covered Cost
2 Reference document #52 Checkpoint 2B submission: preliminary TPM drafting
3 Reference document #56 Letter from EA: Checkpoint 2B submission page 3.
4 Reference document #61 Checkpoint 2B resubmission: Covered cost for BBC
5 Reference document #67 Letter from EA: Checkpoint 2B resubmission

(ii) whether it should be recovered through residual charges (being the least distorting approach).

10. We have taken the Authority's feedback on our Checkpoint 2B submission and resubmission into account in preparing the proposed TPM.

4 Summary of our proposal

11. In developing our proposed approach to covered cost, a critical consideration has been balancing practical considerations against the potential benefits of precision, as we are required to do under the principle in clause 1(b) of the Guidelines. The practical considerations for covered cost include constraints arising from our existing datasets and financial systems, including our regulatory asset base (**RAB**), the primary purpose of which is to help us comply with our regulation under Part 4 of the Commerce Act 1986 and with accounting and taxation requirements. Our existing datasets and financial systems, and the business processes that support them, were not designed with the Guidelines or new TPM in mind, and do not support an approach more akin to direct attribution of costs (to the extent that might be possible) such as that contemplated by Additional Component F.

12. We propose to use an accounting-based allocation approach to attribute capex, opex and other costs to a BBI to build up its covered cost.[6] Under this approach, the costs attributed to a BBI will be:

12.1 directly attributable costs[7], meaning costs wholly and solely incurred in respect of the BBI. This captures capex costs and some types of opex;

12.2 costs that are not directly attributable to the BBI but have a verifiable causal relationship with the BBI.[8] By "verifiable" we mean able to be established and quantified in a robust and practicable way; and

12.3 a portion of other costs where a direct or causal relationship with the BBI cannot be verified (referred to in this chapter as "overhead").

13. In summary, we propose:

13.1 A BBI's covered cost will be calculated annually based on the actual values of the relevant inputs (clauses 36 and 40(1) of the proposed TPM). This proposal means there is no need to calculate the present value of the BBI's covered cost, as anticipated in clause 16 of the Guidelines. Because different types of assets within a BBI will depreciate at different rates, and individual assets may be commissioned, upgraded, refurbished or replaced at different times, the covered cost for a BBI may be "lumpy" over its life. A BBI's covered cost is likely to increase over the early years, until all assets have been commissioned, and then reduce over time as the assets comprised in the BBI depreciate to zero.

---

6 This approach is consistent with the approach the Commerce Commission has developed in input methodologies under Part 4 of the Commerce Act 1986 and Part 6 of the Telecommunications Act 2001.

7 Directly attributable means where a cost (or asset) is wholly and solely incurred in the provision of a particular service/BBI.

8 We understand this captures "shared direct opex" referred to in the Authority's feedback on our Checkpoint 2B resubmission.

13.2 The capex components of a BBI's covered cost will be, for each asset comprised in the BBI, depreciation calculated in accordance with Transpower's input methodologies[9] (i.e. straight line) and a capital charge on the asset's depreciated value calculated using our regulated WACC (clauses 40(1) and 40(2) of the proposed TPM). These values are determined by looking back at depreciation and opening RAB values for the preceding financial year.[10] This approach ensures consistency with the recovery of capital components under Transpower's individual price-quality path (**IPP**),[11] but is a departure from the requirements of clause 17 of the Guidelines in that we will not be using forecast depreciation or capital charge for the pricing year. This is discussed in Section 8.1.

13.3 The proposed TPM contains drafting to deal with the situation where an asset has been commissioned but does not have a RAB value in the preceding financial year (clause 40(6) of the proposed TPM). This is possible because we propose to commence the BBC for a post-2019 BBI from the first pricing year that starts at least six months after the BBI is commissioned, or an earlier pricing year if we determine it is practicable to do so (clause 37(1) of the proposed TPM and paragraph (a) of the definition of "start pricing year").[12] Our proposal to delay the start of the BBC for a high-value post-2019 BBI until the start of a pricing year, which for a high-value BBI commissioned within six months of the commencement of the new TPM may not be the first pricing year, is a departure from the requirements of clause 66 of the Guidelines. Clause 66 requires the BBC for a high-value post-2019 BBI to start when the BBI is commissioned or the commencement of the new TPM, whichever is later. This is discussed in Section 8.2.

13.4 There are some categories of opex and other costs that can practicably be attributed directly to the BBIs they relate to, and we propose to do so. These categories are:

- transmission alternative opex.[13] We propose to attribute this category of opex only to the BBI the transmission alternative is comprised in (clause 41(1) of the proposed TPM, variable TA);
- incremental opex in respect of an approved major capex project.[14] We propose to attribute this category of opex only to the BBI the outputs of the major capex project are comprised in (clause 41(1) of the proposed TPM, variable MCP); and
- Tax costs. We propose to attribute tax costs to the individual assets comprised in BBIs (clauses 40(1), 40(3), (4) and (5) of the proposed TPM).

13.5 There is a verifiable causal relationship between the HVDC link and instantaneous reserve availability costs allocated to Transpower as the owner of the HVDC link.[15] There is also a verifiable causal relationship between the HVDC link and the costs of insuring it.[16] We propose to attribute these categories of opex only to BBIs that

9 Reference document #72 Transpower IMs clause 2.2.4
10 Financial years are used because our RAB is audited at the end of each financial year.
11 Reference document #73 Transpower IPP
12 Clause 37(2) of the proposed TPM provides for the BBC for a low-value BBI to start from a later pricing year. This is because the simple method requires locational information, which can take longer to appear in our financial systems.
13 This is a type of recoverable cost under clause 3.1.3(c) of the Transpower IMs.
14 This is a type of recoverable cost under clause 3.1.3(d) of the Transpower IMs.
15 This is a type of recoverable cost under clause 3.1.3(b) of the Transpower IMs.
16 The majority of our insurance costs relate to HVDC assets, in particular the submarine cables.

comprise investments in the HVDC link (clause 41(1) of the proposed TPM, variable HVDC).

13.6 We propose part of our overhead opex (network and non-network) will be attributed to BBIs by proxy, using regulatory (straight line) depreciation of the assets comprised in BBIs as the basis for the attribution (clauses 41(1), (3) and (4) of the proposed TPM). The share of overhead opex not attributed to BBIs will be implicitly or (in the case of connection assets) explicitly attributed to our non-BBI and non-network assets, and recovered through residual and connection charges.

14. Our proposals for attributing opex and other non-capex costs to BBIs are discussed in more detail in Section 5.

15. We have not included additional component F in the proposed TPM. This is discussed in Section 7.

5 Attribution of opex and other non-capex costs to BBIs

16. The Guidelines require us to apply the principles in clause 1 when choosing between options that comply with the Guidelines. Clause 1(b) is particularly relevant to our choice between options for attributing opex and other non-capex costs to BBIs:

> 1. In developing the **TPM** in accordance with these **Guidelines**, Transpower must, as far as reasonably practicable, use the following principles, including in selecting between options which otherwise comply with these **Guidelines**:
>
> …
>
> b. 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 discretion; and
>
> (iv) costs associated with developing, administering and complying with the **TPM**;

17. There are two key decisions behind our proposals for attributing opex and other non-capex costs to BBIs:

17.1 which categories of our opex and other non-capex costs are reasonably attributable to investments in the interconnected grid (which all BBIs are); and

17.2 on what basis (direct, causal or proxy) should opex and other non-capex costs be attributed to BBIs?

18. Tax is the only type of non-capex "other cost" we have identified that we consider should be allocated to BBIs (clause 15(d) of the Guidelines).[17] This is income tax associated with the capital charges on the assets comprised in BBIs and the tax loss or gain associated with timing differences between the profiles of tax and accounting depreciation of those assets.

[17] Which we would calculate consistently with Transpower's regulatory tax allowance as defined under IPP regulation.

We note the word "reasonably" is missing from clause 15(d) of the Guidelines. This is not significant because our proposal is to allocate tax directly to the relevant assets.

19. The rest of this Section focuses on the attribution of opex to BBIs.

5.1 Interpretation of reasonably attributable

20. Clause 15(c) of the Guidelines requires the covered cost of a BBI to include *"an amount of opex reasonably attributable to the benefit-based investment based on an allocation of the opex allowance for the pricing year as set out in the IPP"*. In our view, it is significant that clause 15(c) does not use the words "directly attributable" or refer to only avoidable or incremental costs being attributed to BBIs.

21. In our view, opex is *"reasonably attributable"* to a BBI if:

 21.1 the opex is directly attributable to the BBI;

 21.2 the opex has a verifiable causal relationship with the BBI; or

 21.3 the opex is overhead (i.e. not directly attributable to or having a verifiable causal relationship with the BBI) and an allocation of part of the opex to the BBI is objectively justifiable.

22. The Commerce Commission has adopted a similar distinction between costs that are directly attributable (and therefore allocated entirely to the asset or service) and costs that are shared (and therefore allocated using causal allocators or proxies). For example, the Commerce Commission recently said this about its approach to determining the value of financial losses under s 177(2) of the Telecommunications Act 2001:[18]

> "The cost allocation rules ensure that only those costs associated with the provision of UFB FFLAS are included in the calculation. This includes costs that are directly attributable to the provision of UFB FFLAS, as well as an allocation of any costs that are shared between UFB FFLAS and other services (ie, not directly attributable to UFB FFLAS)".

23. We consider clause 15(c) of the Guidelines requires the new TPM to attribute a portion of our overhead opex to BBIs. In our view it would be unreasonable not to. All of our investments and services, including BBIs, contribute in some way to our overhead opex. Our overhead opex is not solely attributable to our non-BBI interconnection investments, the costs of which will be recovered through residual charges paid by load customers, and is not solely incurred to provide services to load customers. In our view, if all overhead opex were recovered through residual charges, that would amount to a subsidy from load customers to the beneficiaries of BBIs, would make transmission charges less cost-reflective, and potentially be inefficient. For this reason, we do not consider an approach to covered cost that did not treat some part of our overhead opex as reasonably attributable to BBIs would be consistent with the efficiency limb of the Authority's statutory objective.

24. The reasoning above applies equally to network and non-network overhead opex. We do not consider there is any basis for distinguishing between these types of overhead opex on the basis that network opex is "reasonably attributable" to BBIs but non-network opex is not

[18] Commerce Commission, Chorus' initial price-quality regulatory asset base as at 1 January 2022, Consultation on Chorus' initial price quality RAB proposal, 30 April 2021.

(or vice versa). In our view, it is appropriate for both types of overhead opex to be attributed allocated across our entire RAB and recovered from all customers.

25. In its feedback on our Checkpoint 2B submission, and in earlier feedback on our preliminary proposals, the Authority suggested the Guidelines require all overhead opex to be recovered through residual charges. As discussed above and in Chapter 5 (Connection charges), we do not agree with that interpretation of the Guidelines. We note the Authority did not repeat this interpretation in its feedback on our Checkpoint 2B resubmission.

26. We do not interpret clause 15(c) as preventing the use of a proxy to allocate opex to BBIs. Additional component F (clause 64) of the Guidelines refers to *"a method for allocating opex expended in relation to…assets in a benefit-based investment…[that] must not use a proxy or generalised rule for allocation"* (emphasis added). In our view, the logical inference of additional component F is that, absent its implementation, the Guidelines permit at least some opex (a reasonable amount and type) to be allocated to BBIs by way of proxy or generalised rule.

27. For completeness, we note this is an issue about identifying the correct covered cost of a BII, not an issue relating to the allocation of that cost. In its feedback on our Checkpoint 2B submission (see below) the Authority invited us to *"submit a fuller explanation on why the use of a proxy-based approach for network opex is expected to result in an allocation that broadly relates to net private benefits"*. This is beyond the scope of the covered cost discussion. The Guidelines do not require a BBI's covered cost to match or approximate the value of the net private benefits arising from the BBI.

5.2 Basis for attributing overhead opex to BBIs

28. The Commerce Commission determines Transpower's maximum revenue for each year of a regulatory control period (**RCP**).[19] Our maximum revenue, which is specified in our IPP, includes opex building blocks. These are allowances for:

 28.1 pass-through costs, being rates and levies;[20]

 28.2 recoverable costs, being opex that is difficult to quantify with certainty at the start of a RCP;[21] and

 28.3 operating costs, being most other opex.[22]

29. These building blocks cover both network and non-network opex. They are set at what the Commission considers to be efficient levels for us to operate and maintain our assets while supplying a quality of service that meets our customers' expectations (as reflected in the quality standards and other performance targets in the IPP).

30. Outside of the categories of opex specified in paragraphs 13.4 and 13.5 (which are either directly or causally attributable to particular BBIs), we propose to allocate part of all the opex building blocks referred to in paragraph 28 to BBIs using a depreciation-linked proxy (clause 41(1), variable D_a x AOR, and clause 41(3) of the proposed TPM).

[19] We are currently in RCP3, which runs from 1 April 2020 to 31 March 2025.
[20] Reference document #72 Transpower IMs, clause 3.1.2.
[21] Reference document #72 Transpower IMs, clause 3.1.3.
[22] Reference document #72 Transpower IMs, definition of "operating cost" in clause 1.1.4(2).

31. We consider our proposal to link the proxy to a BBI's depreciation is a reasonable approach for the following reasons:

    31.1 It is reasonable to allocate overhead opex to a BBI in proportion to the size of the investment it represents, which is reflected in its annual depreciation. We agree with the Authority's observation in its feedback on our Checkpoint 2B submission that factors such as asset complexity, asset type, and asset health are also likely to impact on the amount of opex a BBI attracts. However, we consider these variations will broadly even out across the asset types comprised in a typical BBI and over the life of the BBI.

    31.2 Regulatory depreciation is straight line, meaning the proportional attribution of overhead opex to a BBI will not decline as the BBI ages (as it would if the attribution were linked to the BBI's depreciating RAB value). We consider this more accurately reflects the likely distribution of opex of the life of a BBI.

    31.3 The method is simple, non-discretionary and easy to administer, consistent with the principle in clause 1(b) of the Guidelines.

    31.4 The method is transparent for our customers and straight-forward to communicate and explain to them.

32. We propose to use the following attributed opex ratio (variable AOR in clause 41(1) of the proposed TPM), which will apply for a whole RCP unless the IPP is re-opened (clauses 41(3) and (4) of the proposed TPM):

$$AOR = \frac{OC + PC + RC - HVDC - TA - MCP - FD}{D}$$

33. OC, PC and RC are the operating costs, pass-through costs and recoverable costs building blocks for the RCP. HVDC, TA and MCP are the directly/causally attributable categories of opex described in paragraphs 13.4 and 13.5 over the RCP (which are added back into the covered cost of the specific BBIs they relate to in clause 41(1) of the proposed TPM). FD is an amount of opex attributable to fully depreciated BBIs, as determined by Transpower.[23] D is the building block for total depreciation for the RCP.

34. We propose to deduct an estimate of opex for fully depreciated BBIs from the numerator of the attributed opex ratio (effectively allocating that opex to the residual charge) because, at least initially, we expect few of our fully-depreciated assets to be associated with the Schedule 1 BBIs. As such, the costs of those assets would not be recovered through BBCs in any event. We expect this deduction to be around 15% of total opex initially.

35. The majority of assets comprised in BBIs will require 30 to 40 years to fully depreciate, and we would expect most of them to be partially or fully replaced by new BBIs at the end of their expected lives, or to have their covered cost increased through replacement or refurbishment investment. In future, we do not expect there to be a significant number of fully-depreciated assets in our RAB that remain in use and are not replicated by other assets in the RAB that are not fully depreciated. If this proves incorrect, we can consider a future operational review of the TPM to address the issue.

---

[23] We expect this to be around 15%, based on the number of fully depreciated assets still providing transmission services.

36. The attributed opex ratio multiplied by a BBI's annual depreciation gives the BBI's attributed overhead opex for the relevant pricing year. Because the denominator of the ratio is total depreciation, not all of the opex in the numerator will be allocated to BBIs. Some of it will be recovered through the opex component of connection charges and some of it will be implicitly allocated to non-BBI interconnection investments and recovered through residual charges. Residual charges will also recover the opex attributable to fully depreciated BBIs, i.e. the amount of FD in the numerator. As more of our network assets become subject to BBCs over time, the amount of overhead opex recovered through residual charges will reduce.

6 Covered cost calculation – an illustrative example

37. The example below illustrates how the covered cost for a generic HVAC asset and pricing year is calculated under our proposals.

Table 1 Calculation of attributable opex ratio

	Inputs to Attributable Opex Ratio (**AOR**) calculation	
		$m
	Opex (including forecast pass-through and recoverable costs)/RCP total	1,500
	Forecast HVDC insurance and reserve cost/RCP total	60
	Share of opex required for fully depreciated RAB assets	15%
	Forecast cost for transmission alternatives	20
	Forecast depreciation/RCP total	1,300
	Calculation of adjusted Opex/RCP total	
		$m
	Opex (including forecast pass-through and recoverable costs)/RCP total	1,500
less	Forecast HVDC insurance and reserve cost/RCP total	60
less	Share of opex required for fully depreciated RAB assets (=15%(1,500-60))	216
less	Forecast cost for transmission alternatives	20
	Adjusted opex (including forecast pass-through and recoverable costs)/RCP total	1,204
	Calculation of Opex ratio	
		$m
	Adjusted opex (including forecast pass-through and recoverable costs)/RCP total	1,204
divided by	Forecast depreciation/RCP total	1,300
	AOR (applicable to all pricing years in an RCP)	0.93

Table 2 Calculation of covered cost

	Inputs to covered cost calculation for a benefits based investment	
		$m
	Current RAB value (of all assets comprising the BBI)	100.0
	Annual accounting depreciation (straight-line)	2.0
	Annual tax depreciation (diminishing value)	5%
	Vanilla WACC	5%
	Tax rate	28%
	AOR	0.93
	Calculation of capex recovery	
		$m
	Current RAB value (of all assets comprising the BBI)	100.0
multiplied by	Vanilla WACC	5%
	Return on capital (or WACC return)	5.0
plus	Annual accounting depreciation (straight-line)	2.0
	Recovery of capital expenditure	**7.0**
	Calculation of opex recovery	
		$m
	Annual accounting depreciation (straight-line)	2.0
multiplied by	AOR	0.93
	Recovery of operating expenditure	1.9
	Calculation of other costs recovery	
		$m
	Tax (calculation not shown here)	0.3
plus	HVDC insurance and reserve costs	n/a
plus	Forecast cost for transmission alternatives (assumed to be nil)	n/a
	Recovery of other costs	0.3
	Calculation of covered costs	
		$m
	Recovery of capital expenditure	7.0
plus	Recovery of operating expenditure	1.9
plus	Recovery of other costs	0.3
	Covered costs	9.2

7 Additional component F

38. Under clause 54 of the Guidelines, we must propose to implement an additional component in the new TPM if, in our reasonable opinion, we consider doing so would better meet the Authority's statutory objective than not implementing it.

39. We have not included additional component F in the proposed TPM. We have not come to the reasonable opinion that implementing additional component F would better meet any of the limbs of the Authority's statutory objective than not implementing it.

40. At paragraph 14.35 of its 2020 Decision, the Authority said additional component F is designed to, potentially at least, "*promote efficiency*".

41. We consider the practical difficulties, and associated expense, of directly attributing all opex categories to BBIs, to the extent it would even be possible to do so, would not be justified by any efficiency gains, especially against the counterfactual of our proposals for opex attribution. The Authority appeared to agree with this view in paragraph C.18 of its feedback on our Checkpoint 2B resubmission:

> We agree with Transpower that a highly granular approach to direct cost attribution is not required by the main components of the guidelines and agree Transpower's rationale (at para 16 of its 2b submission) for not adopting additional component F appears sound.[24]

42. Our proposal not to implement additional component F is consistent with the principle in clause 1(b) of the Guidelines (practical considerations, including balancing the benefits of precision against the benefits of simplicity and the costs of compliance).

8 Consistency with the Guidelines

43. Except for the matter discussed below, we consider our proposals for covered cost are fully compliant with the Guidelines. See the Guidelines compliance matrix attached to this paper.

8.1 Capex components of covered cost

44. As noted above, we consider our proposal to calculate annual covered cost with reference to depreciation and opening RAB values for the preceding financial year to be a departure from the requirements of clause 17 of the Guidelines.

45. We consider this departure is justified under clause 2 of the Guidelines.

    45.1 We consider the departure is not inconsistent with the intent of the Guidelines. While there will be a "mismatch" between the period used to calculate the capex components of covered cost and the pricing year for which covered cost is being calculated, over the life of the BBI its full capital cost will still be recovered through its BBC, as required by clause 15 of the Guidelines.

    45.2 We consider the departure promotes the efficiency limb of the Authority's statutory objective. The use of forecast capex inputs would inevitably involve some error, necessitating a wash-up mechanism to ensure the capex components of covered cost

[24] Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A-D , paragraph C18.

are not over or under-recovered in the BBI's BBC. This is an administrative burden and cost that can be avoided by using actual capex inputs, albeit slightly backwards-looking ones, instead of forecasts.

46. The departure is also consistent with the principle in clause 1(b) of the Guidelines (practical considerations, including balancing the benefits of precision against the benefits of simplicity and the costs of compliance).

8.2 Delaying start of BBCs for high-value post-2019 BBIs

47. As noted above, we consider our proposal to delay the start of the BBC for a high-value post-2019 BBI until the start of a pricing year is a departure from the requirements of clause 66 of the Guidelines.

48. We consider this departure is justified under clause 2 of the Guidelines.

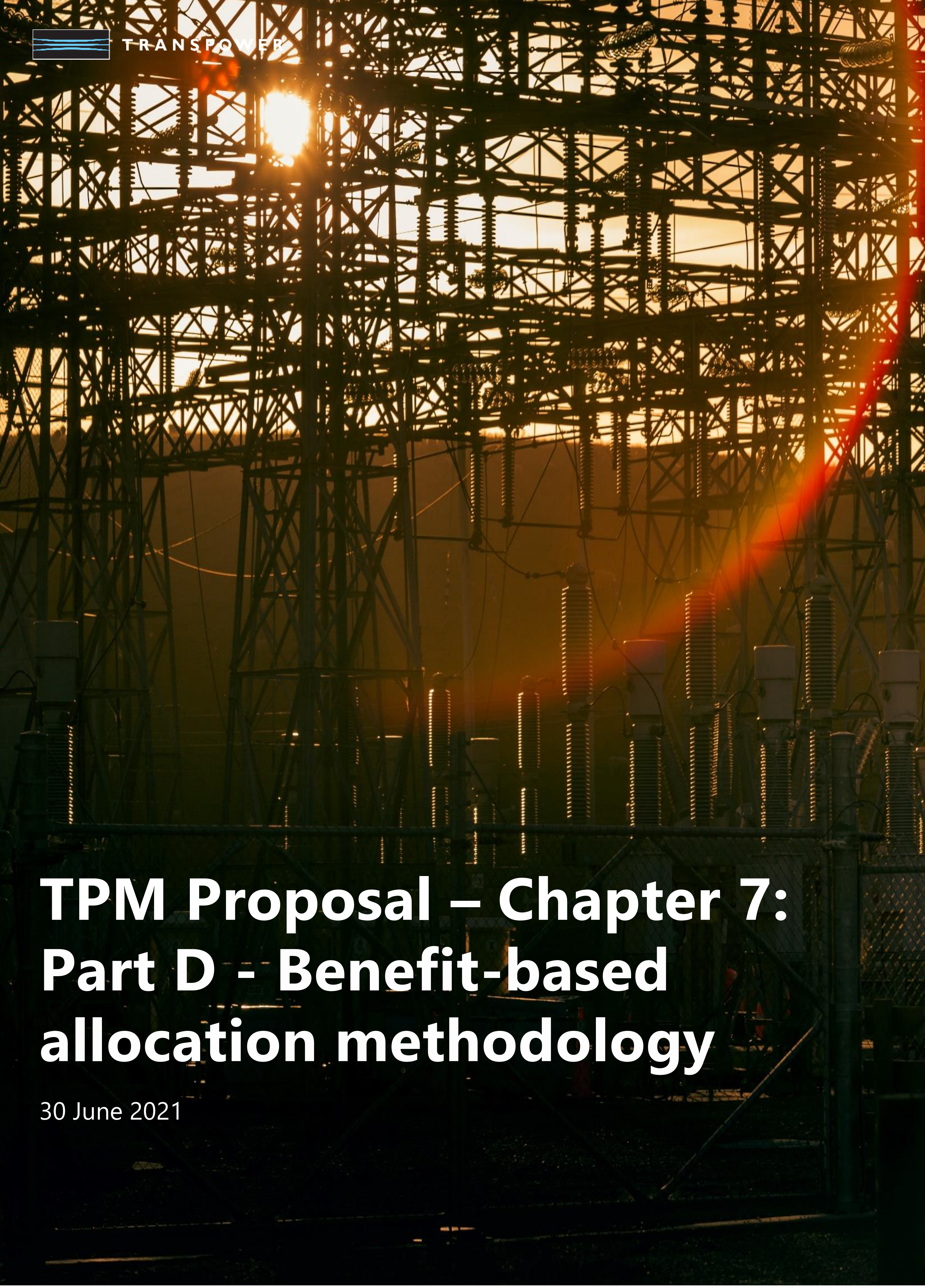
    48.1 We consider the departure is not inconsistent with the intent of the Guidelines. Over the life of the BBI the full covered cost of the BBI will still be recovered through its BBC, as required by clause 15 of the Guidelines. We consider the maximum 18-month delay in the start of the BBC is inconsequential in the context of the life of a BBI, which will typically be several decades.

    48.2 We consider the departure promotes the efficiency limb of the Authority's statutory objective. The six month (or potentially shorter) period of "clear air" before the start of a pricing year allows the calculation, audit and notification of the new BBC to fit within our normal annual pricing process, which is constrained by our obligation to provide our customers with at least three months' notice of their annual transmission charges.[25] This in turn allows time for our customers to incorporate the new BBC in their own pricing processes. This is more efficient for Transpower, our customers and their customers than going through a separate process to reopen (increase) transmission charges during a pricing year.

49. The departure is also consistent with the principle in clause 1(b) of the Guidelines (practical considerations, including balancing the benefits of precision against the benefits of simplicity and the costs of compliance).

[25] Clause 41.5(a) of the benchmark transmission agreement incorporated by reference in Part 12 of the Code.

TRANSPOWER



TPM Proposal – Chapter 7: Part D - Benefit-based allocation methodology

30 June 2021

Contents: Chapter 7

1 Introduction

1. This chapter summarises and explains our proposals for the benefit-based charge (**BBC**) allocation methods in the proposed new TPM.

2. The BBCs are intended to recover the *"covered cost"* of each benefit-based investment (**BBI**). The Guidelines (clauses 18-24) require there must be at least one standard BBC allocation method and may be one or more simple allocation methods. The standard allocation method must be used for "*high-value*" BBIs expected to cost more than $20m.[1] A simple allocation method may be used for all other BBIs ("*low-value*" BBIs, less than $20m).

2 Requirements of the Guidelines

3. Clause (iv) of the Guidelines states the purpose of the BBC:

> The purpose of the benefit-based charge is to ensure that the costs of post-2019 and certain pre-2019 investments in the interconnected grid are (except where the benefits associated with an investment are insufficiently material to warrant the administrative costs of applying even a generalised approach under a simple method) recovered in accordance with the positive net private benefits that each designated transmission customer is expected, as at the time of setting or resetting the charge, to receive from the investment. The positive net private benefit of the designated transmission customer includes the positive net private benefit of any parties whose equipment is electrically connected to the interconnected grid through the designated transmission customer's network.

4. Clauses 8 and 18 to 24 of the Guidelines contain the requirements for BBC allocation methods:

> **General matters**
>
> 8. Where these **Guidelines** require allocations of charges based on expected **positive net private benefits**, the **TPM** must result in an allocation between designated transmission customers that is broadly in proportion to their expected **positive net private benefits**.
>
> **Allocating annual benefit-based charges among customers**
>
> 18. The **TPM** must include one or more standard methods for allocating annual **benefit-based charges**.
>
> 19. The **TPM** may include one or more simple methods for allocating **annual benefit-based charges**.
>
> 20. The **TPM** must provide:

[1] The Guidelines set the threshold for application of a BBC standard method by reference to the **base capex threshold** as defined in the Transpower Capex IM (reference document #71).

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; however, Transpower may adjust the allocations in Schedule 1 in accordance with clauses 31 to 44, including for the purposes of the initial allocation;

c. 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**; and

d. where these **Guidelines** provide for an adjustment to the allocations, a method or methods for making that adjustment. That method(s) must be a standard method, simple method or combination of both, but need not be the same as any other standard, simple or combined method provided for in these **Guidelines**.

21. A standard method 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 the expected **positive net private benefit** to them from the **benefit-based investment** over its **remaining life**.

22. 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** between the designated transmission customers who receive a major **positive net private benefit** from the **benefit-based investment** that is broadly in proportion to expected **positive net private benefits**; 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**. Where a designated transmission customer is so exempted, the simple method must provide for the allocation they would have received to be recovered from those designated transmission customers who have received an allocation of the **annual benefit-based charges** for the **benefit-based investment**.

23. 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**, for **post-2019 benefit-based investments** must be aligned with the treatment of the relevant **electricity market benefit or cost elements** under the **Transpower Capex IM** investment test applied to the **investment** (if any), except to the extent that Transpower reasonably considers such alignment would not result in an allocation between designated transmission customers that is in proportion to their expected **positive net private benefits**.

24. 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.

3 Stakeholder engagement and process

3.1 Consultation

5. In November 2020, we released a consultation paper seeking feedback on options for BBC allocation methods, and for adjusting BBCs and residual charges (TPM options consultation paper). The BBC allocation and adjustments components of the new TPM are interrelated, so we consulted on them at the same time.

6. As part of the TPM options consultation process we ran three online drop-in sessions. These were opportunities for stakeholders to ask questions and seek clarification about our thinking in the TPM options consultation paper.

7. The TPM options consultation paper, submissions, cross-submissions, and videos and transcripts of the three online drop-in sessions are available on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[2]

8. We have taken the submissions and cross-submissions into account in preparing the proposed TPM.

3.2 Checkpoint 2

9. In March 2021, we submitted our preliminary proposals for the BBC allocation methods to the Authority as part of the Checkpoint 2 process.[3]

10. In its feedback on our Checkpoint 2B submission, the Authority commented:

> We recognise the progress that has been made with respect to BBC allocation, noting that both our teams agree that there is still work to do. We are therefore requesting resubmission on this aspect of the proposed TPM." [4,5]

11. The Authority asked us to consider and resubmit on a number of substantive issues concerning to BBC allocation, set out in Appendix B of its feedback. The Authority's feedback also included some less substantive feedback on the BBC allocation in Appendix C.

12. We resubmitted our preliminary proposals for BBC allocation methods to the Authority in May 2021, responding to the matters the Authority had raised.[6]

13. In its feedback on our Checkpoint 2B resubmission, the Authority commented:

---

[2] TPM Development: Options consultation process

[3] Reference document #48 Checkpoint 2B submission: BBC allocation

[4] Reference document #56 Letter from EA: Checkpoint 2B submission

[5] The Authority also provided some additional points for consideration (Appendix C), which it did not request we resubmit in response to. We will consider these points as we prepare our final TPM proposal.

[6] Reference document #60 Checkpoint 2B resubmission: BBC Allocation

> The Authority appreciates the progress Transpower has made in developing its proposed approach to the BBC. … The Authority's further feedback with respect to BBC allocation under the standard method is set out at Appendix A. Feedback on the simple method and our analysis on the allocation of benefit between generation and load is set out for Transpower's consideration at Appendix B.[7]

14. We have taken the Authority's feedback on our Checkpoint 2B submission and resubmission into account in preparing the proposed TPM.

4 Summary of our proposal

15. In developing our proposed approach to BBC allocation methods, critical considerations have been balancing the principles listed in clause 1 of the Guidelines in a manner that is consistent with the Authority's intent for the BBC. Our design decisions have, in particular, been informed by clauses 1(a), 1(b) and 1(e):

> 1. In developing the **TPM** in accordance with these **Guidelines**, Transpower must, as far as reasonably practicable, use the following principles, including in selecting between options which otherwise comply with these **Guidelines**:
>
> a. set charges in a way that:
>
> (i) reflects 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) reflects the share of **positive net private benefits** those designated transmission customers are expected to derive from the matters referred to in (A) to (C) above;
>
> (iii) takes into account, and does not seek to replicate the effect of, other means of controlling demand, including nodal prices;
>
> b. 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 discretion; and
>
> (iv) costs associated with developing, administering and complying with the **TPM**;
>
> …
>
> e. avoid discriminating between designated transmission customers, except to the extent allowed by these **Guidelines** or otherwise necessary to achieve the Authority's statutory objective; and

[7] Reference document #67 Letter from EA: Checkpoint 2B resubmission

...

16. The BBC allocation methods in our proposal will, in our opinion:

    16.1 result in allocations of BBCs between our customers that are broadly in proportion to their expected positive net private benefits (**EPNPB**) (consistent with clause 8 of the Guidelines);

    16.2 apply to all post-2019 investment in the interconnected grid, including post-2019 upgrading expenditure (clause 14(a) and (c));

    16.3 are aligned with the treatment of the relevant electricity market benefit or cost elements under the Transpower Capex IM investment test (clause 23); and

    16.4 support the Authority's statutory objective by being consistent with the Guidelines and the Authority's intent for the BBC (refer to Chapter 2 (Framework for our proposal); and

    16.5 are consistent with determinations by the Commerce Commission under Part 4 of the Commerce Act, including those made under Capex IM processes and requirements applying to Transpower's investment decisions.

17. We propose two BBC allocation 'standard' methods that apply to high-value BBIs:

    17.1 a price-quantity method (clauses 44-53 of the proposed TPM); and

    17.2 a resiliency method (clauses 54-56 of the proposed TPM).

18. We also propose a 'simple' method that will apply to all other investments in the interconnected grid – low-value BBIs (clauses 57-62 of the proposed TPM).

19. The overview diagram below summarises each of the proposed allocation methods.

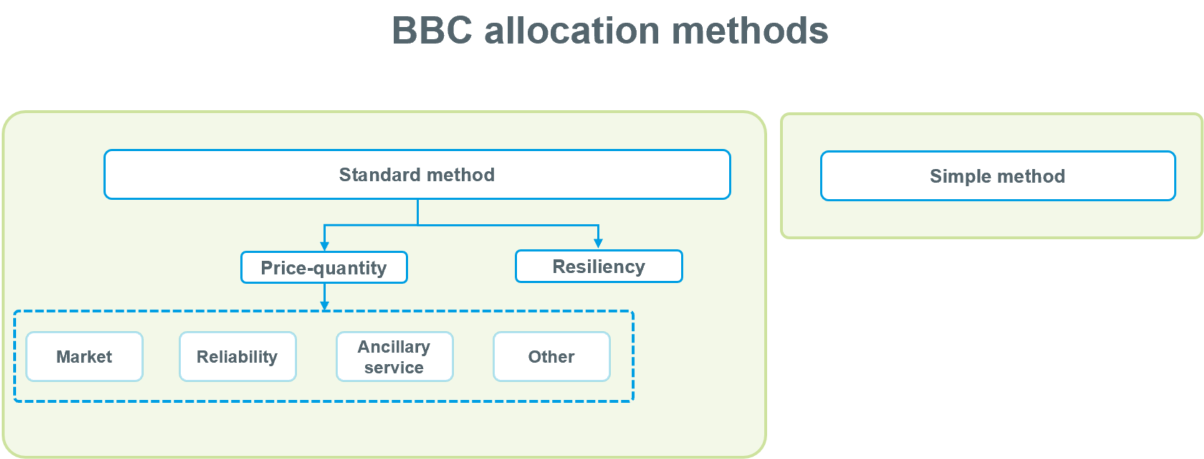


Figure 1 Overview of the BBC allocation methods

4.1 The price-quantity method

20. The price-quantity method (clauses 44-53 of the proposed TPM) quantifies EPNPB using price-quantity modelling aligned with that required by the Capex IM. Within the method, there are four benefit classes for which private benefits are derived through the relationship between prices and quantities:

20.1 market benefits (clause 50 of the proposed TPM);

20.2 ancillary service benefits (clause 51);

20.3 reliability benefits (clause 52); and

20.4 other benefits (clause 53).

21. Key features of the price-quantity method are:

21.1 Beneficiaries are identified using the price-quantity modelling Transpower typically applies for investment test processes under the Capex IM;

21.2 Benefits are determined at a regional level for customer groups and then allocated to individual customers using allocation metrics based on historical meter data;

21.3 Allocations for a particular BBI can be calculated using one or more of the four benefit classes;

21.4 Where multiple benefit classes apply to a particular BBI the regional benefits from each class are determined in dollar terms reflecting price x quantity, based on the system conditions that result in the EPNPB for that BBI.

22. For the market benefit class, as indicated in our 2B resubmission, we are proposing using the price-quantity model such that:

22.1 Beneficiaries are determined based on the price outputs of our wholesale market model; and

22.2 Benefits are allocated between regional beneficiary groups based on the quantity of load or generation during periods when benefits are derived from the BBI, and by doing so, assumes the price change either side of the BBI is equal in magnitude to all regional beneficiaries,[8] unless we consider this will not result in an allocation that is broadly proportional to EPNPB.[9]

23. Our modelling for the price-quantity method case study (see Section 9.9 below and Appendix D (CUWLP case study)), which considers market benefits, has demonstrated that the magnitude of price changes to different beneficiaries is highly sensitive to the underlying input assumptions in some situations. These input assumptions are unavoidably discretionary. The purpose and effect of our proposal in paragraph 22 above is to de-tune the method's exposure to this sensitivity and unavoidable application of discretion. In our opinion this method is necessary in order to achieve allocations that are broadly in proportion to EPNPBs in those situations where the results are particularly sensitive to the input assumptions.

24. In its response to our 2B submission, we received clear feedback from the Authority that it "*consider[s] that the flow-based method's apparent inability to capture value differences (conceptually at least) means that it is likely to be less capable of assessing*

[8] And ignoring the operational cost of generation where there is an increase in the quantity of generation produced. See footnote 32 for more detail.

[9] Clause 50B in the proposed TPM allows Transpower to instead use different price changes to beneficiaries based on the outputs of the wholesale market model where we conclude the method in clause 50A would result in outcomes that are not broadly in proportion to EPNPB.

benefits" and a price-based method "is more likely to produce a proposed TPM which is consistent with the guidelines and with our statutory objective."[10]

25. We consider our proposed approach (50A of the proposed TPM) does not suffer from the same problems as the flow-based method, and is consistent with the Guidelines, because:

    25.1 The flow-based method resulted in an allocation that was (close to) 50:50 for generation and load for the CUWLP BBI. Our proposed method allocates based on the quantity of generation and load benefitting from the BBI (e.g. for CUWLP, ~25% to generation and 75% to load), which – for this BBI – we consider better reflects EPNPB than a 50:50 allocation between generation and load. Where it is not clear and obvious what the price change either side of a constraint should be, the quantity of generation and load benefitting from the release of a constraint, and the amount of time the constraint is binding in either direction are the key parameters that determine NPB and will – in our opinion – result in allocations that are broadly proportional to EPNPB (clause 8 of the Guidelines). Furthermore, clause 50A minimises the discretion and the cost of administering the TPM, and increases its robustness (clause 1(b)) to the extent possible within the Guidelines.

    25.2 The proposed TPM requires we only apply 50A where we consider it will result in allocations that are broadly proportional to EPNPB, such as the CUWLP case study. In other words, we will not make this assumption where we think there is a clear case for using different price changes for different beneficiaries of the BBI. Therefore, our proposal allows for value differences to be assessed where the benefits of precision are likely to be higher than the cost of applying additional discretion (clause 1(b)(iii) of the Guidelines).

    25.3 As is required by clause 23 of the Guidelines, the allocations will be strongly influenced by the key assumptions we are making that result in the BBI passing the investment test (e.g. load and generation forecasts, scenario weightings). Ultimately, for many BBIs, we consider these type of assumptions are more relevant to a BBI passing the investment test than changes to wholesale market prices either side of a constraint, which may only be relevant for determining private benefits. Given one of the Authority's key outcomes for the BBC is to incentivise scrutiny of the investment test from those who are being charged for an investment,[11] it seems pertinent to base the methodology on the assumptions that are most likely to affect the outcome of the investment test – especially where those assumptions are more easily critiqued by the large proportion of our customers who are not participants or experts in the wholesale market (e.g. distributors). In other words, applying clause 1(b) of the Guidelines by balancing the cost of precision with the benefits of simplicity and certainty for our customers.

---

10 Reference document #56 Letter from EA: Checkpoint 2B submission, page 2

11 For example, see reference document #3 2020 Decision, executive summary.

4.2 The resiliency method

26. The resiliency method (clause 54-56 of the proposed TPM) will apply for a sub-set of BBIs that are primarily needed to mitigate high-impact, low probability reliability risks. The benefits derived from these types of BBI cannot be included in the price-quantity method because the factors leading to events which they are required to protect against (such as cascade failure of the power system) have a high range of uncertainty, which prevents a single value (rather than a range) representing the EPNPB from being calculated and combined with the benefits classes in the price-quantity method.

27. For BBIs that are primarily to mitigate cascade failure, the method allocates BBC to offtake customers in the island in which the system event is being mitigated in proportion to their historical offtake. The method also applies to BBIs that are primarily undertaken to avoid a high-impact, low probability event affecting a smaller region, for which we would determine the region being affected and allocate BBCs to all offtake customers in that region in proportion to their historical offtake.

4.3 The simple method

28. The simple method (clauses 57-62 of the proposed TPM) we propose is a regional allocation model. The key features of the simple method are:

    28.1 Modelled region definitions for the simple method use the characteristics of electric power transfer and grid flows to identify regions where primary beneficiaries are broadly aligned.

    28.2 The simple method regional allocation factors (or regional net private benefit - RNPB) for generation and load customer groups in each region are based on:

    - the proportion of generation and load within the region, and grid flows between these regions.
    - a generation and a load weighting factor that that will be updated every 5 years and used to update the split of low-value BBI between aggregate generation and load customer groups as their assessed benefits from accessing the grid changes over time.

    28.3 Allocation to individual customers within a region is based on:

    - the calculated RNPB for each customer group (discussed in paragraph 28.2 above).
    - the customer's proportion of the total regional customer groups injection (for an injection customer) or offtake (for an offtake customer) using the annual average injection and offtake respectively over a 5-year period.

    28.4 The regional definitions, regional allocation factors (or RNPB) and customer proportionate allocation factors will be reviewed at least every 5 years.

    28.5 Once the benefits of a particular BBI have been allocated by the simple method they do not change, except as a result of the adjustments provisions for which our proposals are explained in Chapter 10 (Adjustments).

29. Many BBIs to which the simple method applies are high volume, low-cost (much less than $20m) investments applied across the grid and completed under asset management strategies. Given this context and the Guideline requirements (clauses 1b and 22), our proposed simple method reflects an approach that:

- balances precision with practical considerations
- is administratively simple and lower cost to implement (than the standard method) and
- in our reasonable opinion results in an allocation of BBC between primary[12] beneficiaries broadly in proportion to EPNPB and aligned with the Capex IM.

4.4 Necessary Transpower discretion is mitigated by consultation

30. An unavoidable consequence of the requirement that charges be based on forecasts of benefits that cannot ever be directly measured or observed (as discussed in Section 19) is that the estimation will require subjective judgement and bespoke approaches – that depend on the relevant situation and customers – to the extent precision and robustness is prioritised over simplicity and cost.

31. Matters such as forecast demand and generation, generation cost assumptions, the cost of self-supply, and wholesale market price outputs are not readily amenable to ex-ante specification in the TPM.

32. We have previously commented on how sensitive the pricing outcomes could be to the methodological approach, assumptions and inputs adopted, and our analysis has identified that private benefits are more sensitive to input assumptions than the changes in cost assessed through the Investment test.

33. We are very mindful of the level of discretion Transpower will have to have to apply under a new TPM that complies with the requirements of the Guidelines and that this could result in the application of the BBC being highly contentious amongst our customers given the commercial outcomes and impact on individual customers and, ultimately, on end-consumers. While a more formulaic methodology would reduce discretion, it would also risk resulting in anomalous allocations that are not broadly proportional to EPNPB (e.g. PJM's Artificial Island example[13]).

34. In order to attempt to mitigate against discretion we are aiming to make the application of the BBC as transparent as practicable, and to enable customers and other stakeholders to engage with us in the pricing determination process.

35. We have accordingly included a number of mechanisms in the proposed BBC, including:

    35.1 We have designed the proposed TPM to contain the fundamental and structural elements of the methodology.

---

[12] We will also refer to these as primary beneficiaries. See reference document #4 Guidelines, clause 22.

[13] For discussion of this example, see the Beneficiaries pay in USA joint report

35.2 The use of historical data rather than forecasts where we consider these good proxies for EPNPB (e.g. individual customer allocators, the simple method contribution factors and regional model definition).

35.3 A mandatory requirement for Transpower to develop an "assumptions book". The "assumptions book" will provide greater (upfront) certainty about how the TPM will be operated and charges will be calculated.

35.4 The TPM includes mandatory requirements for Transpower to consult with its customers and/or publicly on various elements of the operation and application of the BBC. By way of example:

35.4.1 For high-value BBIs, Transpower must consult on the proposed annual covered costs and expected BBI customer allocations on an investment-by-investment basis before the relevant transmission charges to them are finalised.

35.4.2 Transpower must consult publicly on the proposed modelled regions and regional NPBs under the simple method and proposed simple method factors.

35.4.3 Transpower must consult on the assumptions book.

35.4.4 This is also complemented by the Part 4 Commerce Act consultation requirements on Transpower's investment and expenditure proposals.

5 Price-quantity standard method: Overview

36. This section provides an overview of our proposal for the standard method and introduces some key concepts that underpin our approach. The analytical process steps for the standard method are then explained in subsequent Sections 6 to 14.

37. As noted above, a standard allocation method must be used for all high-value BBIs (>$20m). Clause 23 of the Guidelines requires that:

> "… the treatment of benefits and costs used to calculate **net private benefits**, for **post-2019 benefit-based investments** must be aligned with the treatment of the relevant **electricity market benefit or cost elements** under the **Transpower Capex IM** investment test applied to the investment (if any) …".

38. In other words, if an investment is required to satisfy the 'investment test', [14] the private benefits used to determine BBCs need to be consistent with (but not necessarily the same as) the benefits calculated under the investment test. We consider that our proposed standard BBC methodology will work alongside the investment test because it is based on our existing framework for undertaking cost-benefit analysis. In submissions to our options consultation, there was strong support for a modelling approach that aligns with the investment test.

[14] The **investment test** is specified in Transpower Capex IM, Schedule D (reference document #71). Note, major capital projects must pass the investment test, whereas base capex projects or programmes greater than $20m must have a cost-benefit analysis consistent with determining expected net electricity market benefit (clause 3.2.1).

39. The investment test itself is not a detailed procedure for undertaking cost-benefit analysis. It describes the types of benefits we can consider[15], and specifies some parameters we should use e.g. discount rate. There are many aspects of cost-benefit analysis that are not specified in the investment test. However, pricing is a different context which would ideally be more formulaic in order to minimise discretion and debate over the application of the TPM (as recognised in clause 1(b) of the Guidelines). Therefore, the TPM needs to provide more detail of some aspects of the benefit analysis undertaken to determine BBC allocations.

40. For the purpose of the TPM, we have broken down the process to determine allocations into three steps, which are summarised in the diagram below:

41. **Step 1: Quantifying the benefits.** This step quantified and allocates benefits to regional load and generation beneficiary groups.

42. **Step 2: Translating the benefits to a proportion.** This step undertakes some adjustments on the benefits calculated in the preceding step such as removing disbenefits and discounting annual benefits to a single present day value.

43. **Step 3: Allocating to customers.** This step allocates each load and generation group's proportion of the BBC to individual customers, using a proxy of their historical offtake and injection relative to other beneficiaries. This proportion represents the proportion of the covered cost each customer will pay. As per the Guidelines, the proportion is fixed over the life of the BBI and will not change unless one of the Adjustments provisions are triggered.

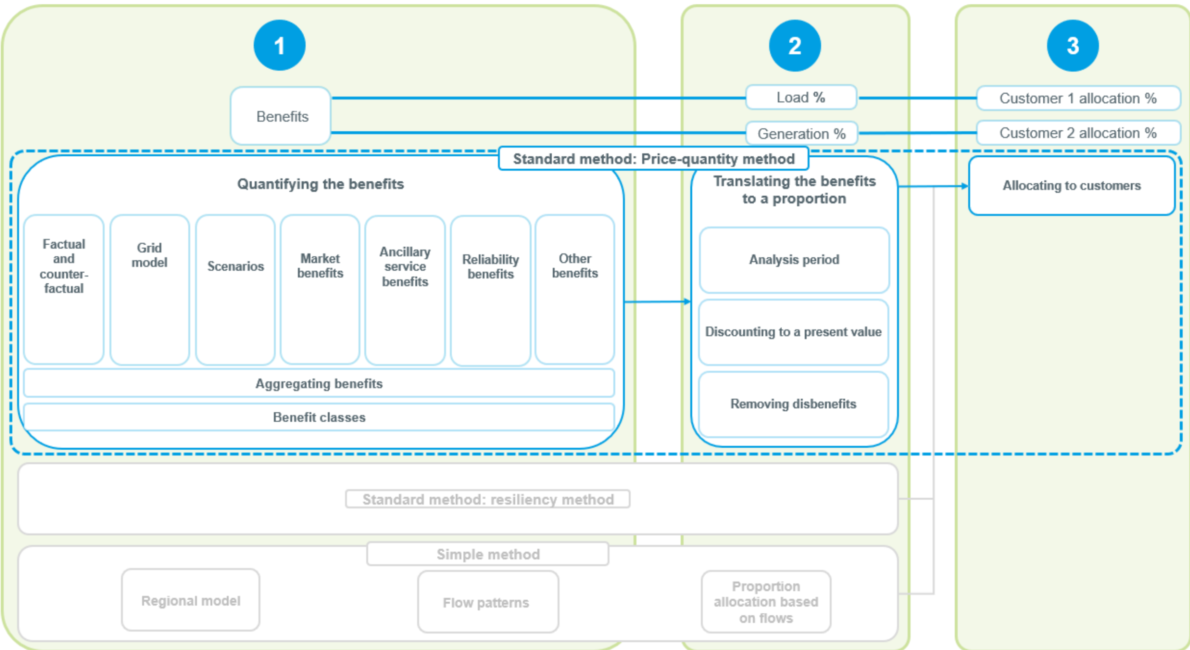


Figure 2 Price-Quantity standard method allocation process

44. Our approach to the price-quantity standard method is a methodology that aims:

15 Note, the investment test assesses reductions in electricity market costs (also referred to as efficiency benefits), whereas the TPM Guidelines require an assessment of private benefits, which include wealth transfers between parties within the electricity market.

44.1 for alignment with the investment test as it exists today – for example, through use of the same or similar models we currently use for cost-benefit analysis.

44.2 to balance the trade-off in minimising the adverse effects of false precision with the Guideline's requirement to allocate charges broadly in proportion to expected benefits (clause 8 of the Guidelines).

45. In our proposal for quantifying market benefits[16] through the standard method we are proposing a methodology that determines regional beneficiaries based on the price outputs of the market model, and uses the quantities during periods of benefit to determine the allocations between these regional beneficiaries where we consider this will result in allocations that are broadly proportional to EPNPB (clause 50A of the proposed TPM). Where we do not, we are proposing to allow for different beneficiaries to receive different price changes based on the outputs of our market model (clause 50B of the proposed TPM). Both methods rely on the commercial modelling tools Transpower uses for system planning and economic analysis under the investment test.

46. We have chosen to propose this approach to determining allocations for market benefits because:

46.1 The change in market price due to a constraint is not always the most significant factor in determining private benefits – the amount of time a constraint is expected to bind, and the volume of load or generation exposed to a change in price is often more important.

46.2 The prices that are produced by our market models are based on the operational cost of generating electricity; therefore, they will not always be fully reflective of the capital cost of new modelled generation investment (particularly marginal generation), which may be important when assessing dynamic efficiency benefits. We may need to adjust prices in post-processing to capture these benefits. We prefer this post-processing approach as it will be significantly more transparent that an attempt to conform a complex wholesale market model to produce the market price outputs we expect to see.

47. We do not consider the forecast market prices from our wholesale market model (described in Section 9) to be sufficiently accurate to be used in situations without a clear cause, for two reasons:

47.1 Our analysis of the market prices from these models indicates the prices are more sensitive to input assumptions than the electricity market costs produced by these models used when applying the investment test. This is possible because the benefits measured by the investment test are conceptually and mathematically different (although related to) private benefits (see Section 9.7).

47.2 We acknowledge the wholesale market prices from our models are only a proxy for actual wholesale market prices, which are influenced by factors that we

16 Market benefits refer to material changes in prices or quantities in the wholesale market due to a BBI.

cannot model without a high level of discretion (e.g. market power[17]), or because any model makes simplifying assumptions for practical reasons (e.g. not modelling random generation outages or transmission losses).

48. However, conceptually, there are situations where different changes in price to different beneficiaries are likely to be particularly important predictor of EPNPB, and where we can be more confident this are actually representative of EPNPB rather than an unintended artefact of the wholesale market model's sensitivity to input assumptions – e.g. where there is a material magnitude of unserved energy due to a capacity shortage. Therefore, we have retained the ability for us to assume a different price change applying to different beneficiaries.

5.1 Step 1 (Quantifying the benefits): Overview

49. This section introduces the key features and concepts underpinning our proposal for the first of three steps in the BBC standard method (quantifying the benefits), which comprises several sub-steps.

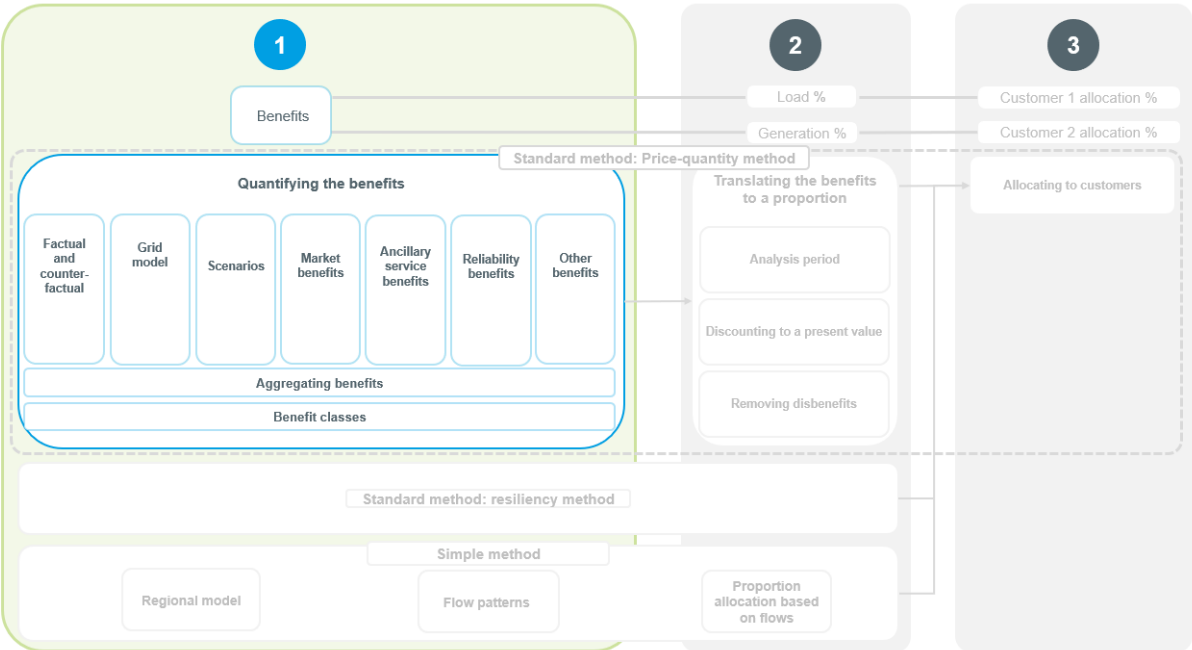


Figure 3 Price-Quantity standard method step 1

5.2 Aggregating benefits

50. Our proposal is to, at step 1, aggregate benefits into regional load and generation groups and then later (at step 3) allocate benefits within these groupings to individual customers.

17 Noting our proposal is to model generation dispatch and market prices assuming a perfectly competitive market, which is clearly a proxy for reality. For example, as noted by Meridian in its cross-submission on the 2019 UTS Proposed Actions to Correct: "A cap on offers at SRMC has never been a part of the normal operation of the market even when spilling."

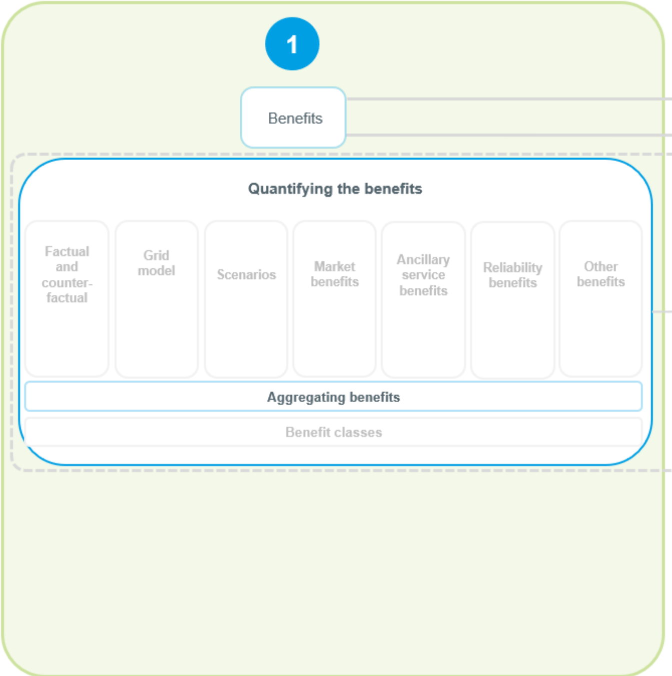


Figure 4 Price – Quantity standard method: step 1 Aggregate benefits

Our proposal

51. Private benefits will be calculated for groups of customers before allocating to individual customers:

    51.1 Electrically connected offtake and injection customers will be aggregated into regions that are likely to receive similar benefits (in proportion to the size of the customer or electrical node). These regions change for each BBI based on the outputs of the wholesale market model. We have introduced the concept of regional groups in clause 44(2)(a) of the proposed TPM.

    51.2 For market benefits, offtake and injection customers within the same region will also be aggregated into sub-groups within a region that are expected to receive similar benefits. We have implemented the concept of sub-groups of offtake and injections customers (referred to as regional customer groups) in clause 50A(2) and 50B(2) of the proposed TPM.

Rationale

52. We consider an aggregate regional offtake and injection approach will result in the standard method being less complex and more reflective of private benefits.

53. Without aggregation, individual allocations are likely to be sensitive to each individual modelling assumption. As a result, there is a greater risk of allocations of benefits that do not reflect private benefits. For example:

    53.1 Small differences in assumptions about the operational cost of two otherwise identical generators would result in one generator always being dispatched before another in a least-cost dispatch model. While this type of modelling outcome is not material for determining the aggregate benefit of a transmission investment, the private benefits of the two generators may be modelled as being very different, which would not be realistic. By aggregating, we can produce allocations that better reflect the private benefits of generators.

53.2 Input assumptions such as load forecasts are statistically more predictable at an aggregate level, because positive and negative errors at a more granular level cancel each other out. For example, the load forecast in a region is more likely to be accurate than the load forecast at an individual electrical node, which can be very sensitive to an individual end-use consumer connecting or disconnecting.

53.3 Aggregating first, then allocating back to the individual customers, means any forecasting inaccuracies or simplifications are shared across electrical nodes within a given category. Provided the nodes within an aggregate group are likely to have similar benefits, the final allocation to the nodal level is more likely to be accurate for individual nodes. Grouping in this way minimises the risk of charges discriminating between customers (1(e) of the Guidelines) in a way that doesn't reflect EPNPB, which would impede competition in the electricity market (counter to the competition arm of the Authority's statutory objective).

54. We note a regional approach was the approach the Authority advocated during the second TPM Issues Paper consultation and subsequent Supplementary Consultation.[18] The Authority subsequently decided to take a less prescriptive approach to elements of the Guidelines and apply a principles-based approach to adoption of BBCs, which would provide Transpower flexibility and discretion to determine the best BBC methodology as part of the TPM development process.

55. Having considered our position further since our 2B submission, we have now allowed for offtake customers to be aggregated into sub-groups as well as generators. This is to account for offtake customers for which the individual customer allocation metric (see Section 14) may not best represent their proportion of net-private benefits when grouped with other offtake customers. In particular, connection locations with a large proportion of embedded generation or electricity storage which regularly both inject and offtake from the grid. For many BBIs, we expect injection to disbenefit from a BBI when offtake in the same region is benefitting (or vice versa). Grouping offtake customers with material injection with other offtake customers who only offtake from the grid would not result in an allocation that offsets the injection of these customers.

56. The CUWLP case study demonstrates how our aggregation approach may work in practice, although we expect to develop and refine the methodology over time, documented in the assumptions book.

57. Section 7 explains our approach to determining the constraints that will be applied in the market model, which is a key factor towards determining the regions that would form from a BBI.

58. Among those submitters that provided a view on aggregating benefits in our options consultation, there was majority support for the aggregation of benefits to regions and injection groups before individual customers. [19]

---

[18] Authority, Transmission Pricing Methodology: issues and proposal, Second issues paper, 17 May 2016 and Transmission Pricing Methodology: Second issues paper, Supplementary consultation, 13 December 2016

[19] Refer submissions and cross submissions TPM Development: Options consultation process

59. For example, Meridian "*agrees that aggregation can alleviate the impact of modelling errors on individuals and spread the impact of input assumptions that do not align with reality. However, the identification of regions and types of generation for aggregation purposes will involve a high level of discretion by Transpower and have potentially significant impacts on transmission charges. We would need to see further details of the aggregation proposed to make an informed assessment of whether the judgements made are reasonable. The other aggregation dimension is the location – or region – of beneficiaries.*"

60. On the other hand, Counties "*is concerned with the proposal to aggregate benefits to regions. This risks allocating Auckland wide transmission costs, and new large industrial connections north of Counties Power, to Counties Power's consumers who are on the southern boundary of the Waikato Upper North Island Region*." Similarly, Northpower stated "*When Transpower invests to alleviate the Auckland congestion, Northland is deemed to "benefit" from the reduced energy prices – but it was never compensated for the original increase in energy prices driven by Auckland's growth and congestion. This in effect results in Northland consumers subsiding Auckland's growth. It also does not send an effective price signal to new consumers in Auckland, to incentivise them to connect where capacity exists on the grid*." The Guidelines require the BBC to be a benefit-based methodology rather than a causer/exacerbator pays methodology. In the absence of transmission upgrades, all parties downstream of a constraint will incur higher wholesale market prices even if they have not increased their use of the grid. The regional aggregation approach is not intended to group customers who have significantly different benefits (in proportion to their size). Rather, it is intended to reduce the impacts of false precision created by modelling assumptions (e.g. of an individual customer's marginal production costs) and unrelated transmission constraints. If a load customer is not downstream of a market constraint they will not receive market benefits under the standard method. Therefore, we do not consider estimating benefits for individual customers without first aggregating into regions to be a solution to Counties and Northpower's concerns.

5.3 Benefit classes

61. This section describes the four benefit classes we have identified for assessment and allocation through step 1 of the standard method: market benefits, reliability benefits, ancillary service benefits, and other benefits.

Figure 5 Price – Quantity standard method step 1 Benefit classes

Our proposal

62. Allocations under the price-quantity method will be calculated using four benefit classes: market benefits, ancillary service benefits, reliability benefits, and other benefits (clause 44(2) of the proposed TPM).

63. Not every BBI will use all benefit classes – Transpower will determine which classes will be used for each BBI based on the nature of the investment (see definitions of reliability, market, and ancillary service BBI, clause 53, and clause 44(2) in the proposed TPM).

Rationale – benefit classes

64. Transpower and stakeholders use many names for the benefits derived from transmission, including security, availability, dispatch benefits, and capacity. However, fundamentally, the transmission grid provides two types of benefits to electricity consumers and suppliers:

- by connecting generation and load in a nationally competitive market, transmission allows loads to access the lowest cost generation, and generation to access load throughout the country.
- a reliable supply of electricity, including a more reliable supply than can be economically achieved by smaller regional grids or the self-supply of electricity.

65. We have named these two benefit classes “market benefits” and “reliability benefits” respectively.

66. For the purpose of the proposed TPM, we classify avoided unserved energy due to a security constraint applied through the market model as a market benefit – in other words, for the purpose of the TPM, we are assuming constraints will be left to bind by

the system operator with high prices being observed downstream of the security constraint, rather than the system operator managing demand before a constraint binds without a resulting impact on the wholesale market. However, we note for the purpose of our obligations under the grid reliability standards, we consider avoiding excessive load management (either by the system operator or in response to very high prices) to be a reliability benefit.

67. Occasionally, a transmission asset may reduce ancillary service costs – for example, the HVDC Pole 3 investment reduced the quantity of frequency keeping and reserves procured from generators. Therefore, we have also included this as a benefit class, although we expect to use it infrequently.

68. In addition to these three benefit classes, we have included a class called "other benefits" (described in Section 12). Clause 23 of the Guidelines[20] requires the BBC to consider benefits that are not part of those considered under the investment test where *"Transpower reasonably considers such alignment [of investment test benefits] would not result in an allocation between designated transmission customers that is in proportion to their expected positive net private benefits."*

69. We have interpreted this as either benefits that are unforeseen at this time, or benefits that are not one of the electricity market benefits we can consider under the Capex IM. We expect to use the "other benefits" class infrequently.

70. Under the Capex IM, we can consider unquantified benefits when making investment decisions when the cost of calculating them is likely to be disproportionate to their magnitude, where they are fundamentally uncertain in magnitude, and where the difference in project cost between two options is less than 10% (or another percentage proposed by Transpower). The reference to unquantified benefits is useful when making investment decisions because they can help us decide between investment options. We have not included unquantified benefits as a benefit class precisely because they are unquantified and therefore are not useful in trying to determine quantified allocations – allocation under BBC requires information not just on direction but also on magnitude.

71. We received general support for the concept of market and reliability classes in submissions to our options consultation.

72. There were some comments criticising the concept of reliability benefits within the context of the grid reliability standards.[21] For example:

    72.1 Network Waitaki thought *"Any identified investments required in a region to bring the transmission grid in that region up to current grid reliability standards (where there has been a historic shortfall or non-compliance) should not be subject to benefit based allocation and should be socialised through the residual charge."* While the Guidelines do not allow for any investments to be excluded from the BBC on this basis, we also note that we are not aware of any regions not currently in compliance with the grid reliability standards.

---

20 Reference document #4 Guidelines

21 Refer submissions and cross submissions TPM Development: TPM Options consultation process

72.2 Creative Energy Consulting (CEC) for Trustpower: *"The grid reliability standards (GRS) include a deterministic requirement, that relates directly to the capacity and topology of the transmission network, as opposed to the market benefits that flow from that. The GRS must be maintained, irrespective of the associated costs or benefits. Since the value of compliance cannot easily be modelled, it will also be difficult to model which customers receive this value. So, it is likely that some simple distribution of benefit will need to be assumed: e.g. that all customers benefit, in proportion to their size, right across the market."* The Guidelines require Transpower to allocate charges for each BBI between designated transmission customers broadly in proportion to their expected positive net private benefits, regardless of whether net private benefits exceed the covered cost or not.

73. In addition, there were several comments on specific design decisions that we address in Sections 9 to 12 below.

6 Price-quantity standard method step 1: Factual and counterfactual

74. This section describes, for the standard method, our proposed approach to the first step required to quantify benefits: the principles we propose to use for defining factual and counterfactual futures against which changes in expected net private benefits can then be quantified.

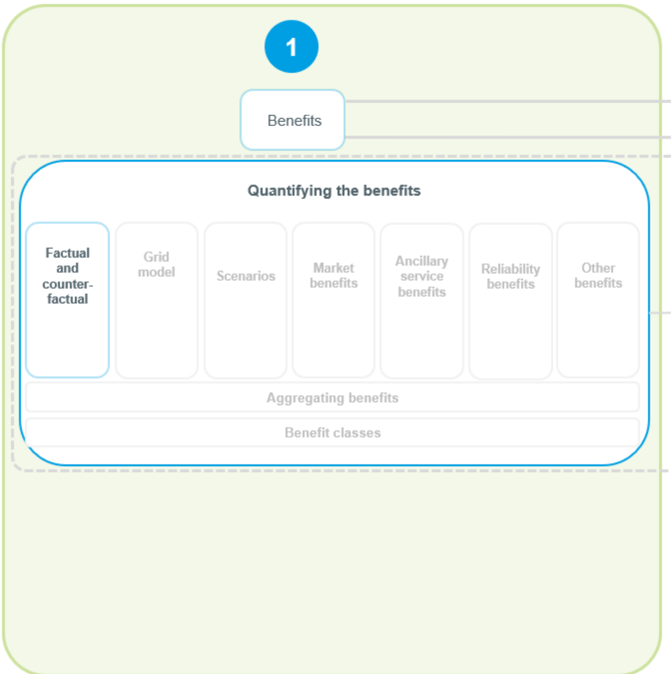


Figure 6 Price -Quantity standard method step 1 Factual and counterfactual

6.1 Our proposal

75. Transpower must determine a factual and counterfactual for a given BBI (45(1)).

76. The counterfactual will be determined by Transpower based on the following principles (45(2)):

- if a grid investment comprised in the BBI is an enhancement investment, the counterfactual must include the grid investment not being made
- if a grid investment comprised in the BBI is a replacement investment or compliance investment, the counterfactual must include the immediate decommissioning of the relevant grid asset or transmission alternative without replacement
- if a grid investment comprised in the BBI is a refurbishment investment, the counterfactual must include leaving the relevant grid asset or transmission alternative in operation without refurbishment until it reaches replacement state and then immediately decommissioning it without replacement.

77. If in Transpower's reasonable opinion none of these counterfactuals represent the most likely future without an investment, Transpower will select an alternative counterfactual (45(2)). For example, some investments may have multiple drivers and therefore may require a combination of these counterfactuals.

6.2 Rationale

78. Given the counterfactual is an important factor in determining the beneficiaries of an investment, we consider it necessary to include counterfactual principles in the TPM. The principles have been developed based on the most likely future of the grid if the most common classes of investments were not undertaken. We have included provision for Transpower to use a different counterfactual for a situation where we consider applying these principles does not produce a reasonably likely future grid state (e.g. where there is both a condition and enhancement driver for a BBI).

79. In submissions to our options consultation, Contact, ENA, and Meridian agreed with the counterfactual principles.

80. Network Waitaki thought "*the principles discussed do not appear to sufficiently address a situation of over-capacity in generation in the counterfactual*." In our view the proposed counterfactual principles will allow for situations of over-capacity. For example, if we were doing significant maintenance on the HVDC, we think the counterfactual should be the removal of the HVDC (one or both poles depending on the extent of the maintenance). This would likely show over-capacity in the South Island and under-capacity in the North Island during most hydrological scenarios.

81. NZIER for MEUG *"support a principles-based approach"* but questioned how investments with interdependencies or conflicts with other investments will be resolved. We think it may be appropriate to group BBIs with a common driver into a single BBI – in which case they would share the same counterfactual. For this reason, clause 45(2) of the proposed TPM allows some flexibility in setting counterfactuals.

7 Price-quantity standard method step 1: Grid model

82. This section describes the transmission grid model and associated transmission security constraints we propose to use to support the BBI beneficiary identification and benefit quantification for market benefits in the standard method.

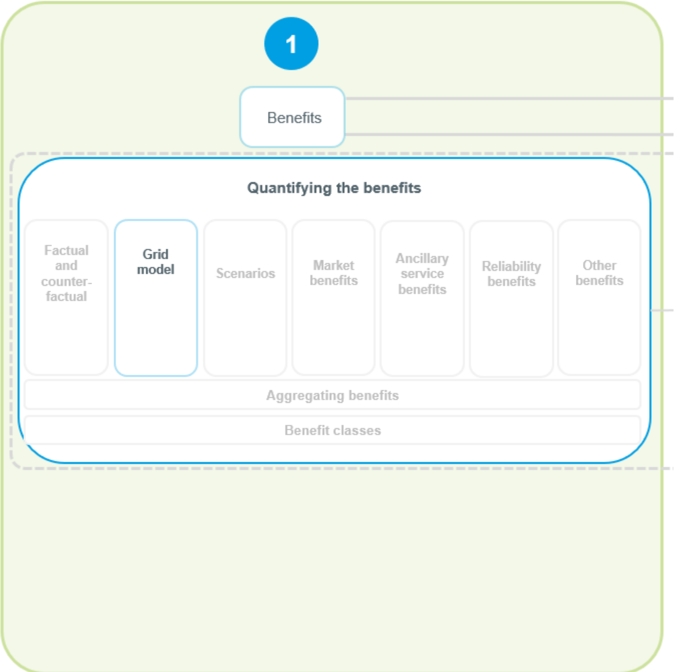


Figure 7 Price – Quantity standard method step 1 Grid model

7.1 Our proposal

83. Our proposal is to use a grid model that only uses transmission security constraints relating to the BBI and the HVDC (investment grid) to be used in the market model for electricity market BBIs (50(2)).

84. Per the definition in the proposed TPM, an investment grid:

    84.1 is developed in two grid states:

        84.1.1 the counterfactual without the BBI

        84.1.2 the factual with the BBI.

    84.2 uses a nodal transmission network in both grid states.

    84.3 in each of the grid states, only includes transmission security constraints related to the:

        84.3.1 BBI

        84.3.2 inter-island HVDC link.

85. The transmission security constraints related to the BBI is defined in the TPM as modelled constraints which include transmission security constraints:

    85.1 on the assets that are part of the BBI

85.2 materially alleviated by the BBI.

86. The investment grid will likely be different for each BBI intended to deliver market benefits and assessed via the standard method.

87. The reliability model has an analogous concept called a system limit model that is discussed in Section 11.

7.2 Rationale

88. The investment grid uses a full nodal network representation of the grid. It includes transmission security constraints on BBI assets, transmission security constraints on assets materially alleviated by the BBI and excluding those unrelated to the investment being assessed, the exception being the HVDC.[22]

89. A BBI that comprises a portfolio of projects all relating to the same investment driver can be accommodated within the investment grid. For example, by including constraints relevant to the portfolio that could be updated as each new investment in the portfolio is planned to occur.

90. The nodal network transmission representation allows the investment grid approach to more accurately capture branch flows (compared to a reduced network model) in the factual and counterfactual grid states and therefore more accurately capture the impact of the BBI on the related transmission security constraints.

91. The intention of the investment grid when used with the wholesale market model is to:

    91.1 help capture the load and generation customers in a region that are likely to receive similar benefits due to the BBI so that the primary beneficiary regions can be identified recognising these regions would be different for different BBIs; and

    91.2 reduce the risk of binding constraints in the market model with subsequent price effects in areas of the grid that are not related to the BBI under investigation. This makes the identification of the primary beneficiary regions impacted by the BBI less susceptible to forecast errors and assumptions of future generation, load and transmission evolution which are less predictable at more granular levels.

92. If all transmission constraints are retained throughout the modelling horizon, benefits will be unrealistically concentrated on customers local to the investment. Over time, we would expect downstream constraints to be resolved through additional transmission or generation investment. An alternative to this approach would be to use modelled (i.e. possible future) transmission or generation projects to resolve constraints. We do not consider this a practical option due to the complexity required to determine a preferred solution and cost[23] to resolve all grid constraints with modelled projects over 20 years. In other words, we would be required to plan the entire grid for 20 years for each scenario. Such an approach would likely be highly discretionary due to the simplifying assumptions required to make the process

[22] We consider the inclusion of HVDC transfer limit constraints is appropriate as it is a less complex constraint than for AC transmission circuits, and it may contribute to creating more granular regions under clause 50B of the proposed TPM, should that clause be used for any given BBI.

[23] With sufficient accuracy for a pricing methodology.

manageable and would increase the cost of administering the TPM (clause 1(b)(iv) of the Guidelines).

93. It is expected the process for creating these transmission security constraints would be provided in the assumption book.[24] This would increase the transparency of the constraint creation process in the investment grid.

94. Most submitters who responded to the investment grid approach in the options consultation paper broadly agreed with using a less detailed transmission representation in the beneficiary assessment market model to avoid the pitfalls of false precision over the modelling horizon. While agreeing with the issues raised against using a full grid model over the modelling horizon, Meridian, in its submission, considered the potential merits of including a beneficiary assessment using a nodal model, as a "*sense check*" to the investment grid.

95. The investment grid uses a full nodal topology and uses transmission security constraints related to the relevant BBI, including the HVDC. Over the modelling horizon, underpinning forecasts and assumptions (such as load forecasts and future generation) are less predictable at the nodal level than at an aggregate level. As discussed above (Section 5.2), we do not consider the assessment of benefits calculated directly at the nodal level could be more precise, or more accurate, than our proposed approach.

96. In its response to our checkpoint 2B resubmission, the Authority requested we specify areas for, and the nature of, judgement provided for in the investment grid methodology.

97. It is in Transpower's interest to reduce the level of judgement in this process however there is also a tension in trying to ensure the process and therefore the market model does not produce spurious outcomes that ultimately is not in anyone's best interest. We see this as a risk of trying to make the TPM too prescriptive.

98. To balance the risk of unintended outcomes with providing increased transparency, we are proposing a constraint creation process that is relatively formulaic to reduce the level of judgement required in developing constraints for the investment grid. We anticipate including this process in the assumptions book.[25] The process does allow for some flexibility by:

    98.1 requiring use of scenarios (system conditions) for developing these constraints that would be updated for the relevant BBI.

    98.2 using thresholds on constraint limits for determining the extent to which an alleviated constraint is assessed to be related to a BBI.[26]

[24] See Section 18 for further discussion on the assumption book.

[25] An indication of what this process might look like for modelled thermal constraints is provided in Section 20 of this chapter.

[26] We consider these alleviated constraints materially impacted by the BBI are ones that either include the BBI (as the protected circuit) or includes constraints whose loading: (a) exceeded a specified threshold without the BBI and (b) reduced by greater than a specified threshold with the BBI.

99. The description of the scenarios (system conditions) and threshold settings used to create the relevant constraints related to the BBI is expected to be specified during the BBI consultation.

8 Price-quantity standard method step 1: Scenarios

100. This section describes the rationale for the clauses relating to scenarios in the proposed TPM.

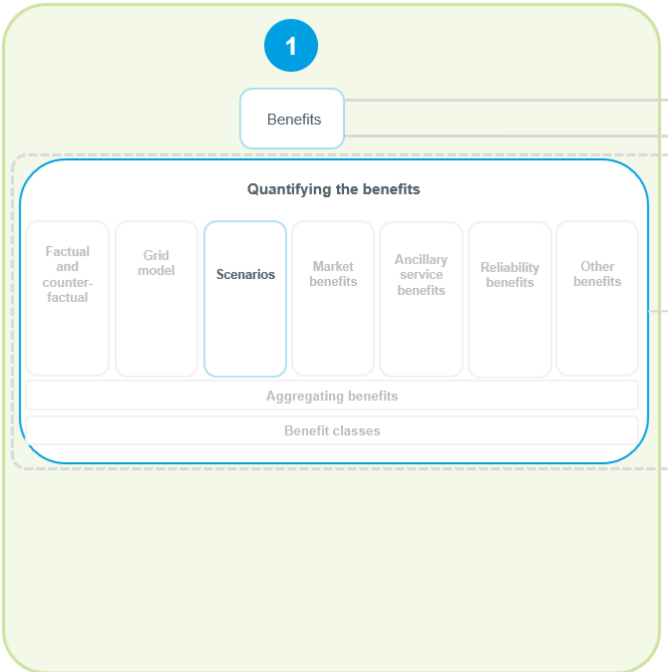


Figure 8 Price – Quantity standard method step 1 Scenarios

8.1 Our proposal

101. Transpower will determine market scenarios for use when quantifying regional NPB under the standard method (46(1)).

102. Where a post-2019 BBI is a tested investment, the scenarios and other assumptions must be as consistent as reasonably practicable with the assumptions and other inputs used in applying the investment test, except to the extent these assumptions would not produce allocations that are broadly proportional to net-private benefit (43(3)).

103. Transpower must use the same scenarios in the counterfactual and factual, except where we expect the BBI to materially influence generation investment (46(2)).

104. Where a market scenario includes the disconnection of a customer, we will not apply that scenario to the customer when calculating their allocation (46(3)).

8.2 Rationale

105. Under the investment test, we are required to use MBIE's EDGS (or reasonable variations on the EDGS). Clause 43(3) of the proposed TPM requires us to use assumptions that are aligned with those used in the investment test, except where

these produce allocations that are not broadly proportional to EPNPB (as required by clause 23 of the Guidelines). Ideally, we consider it preferable for the EDGS to be used without variation as this would limit the need for us to exercise discretion (1(b)(iii)) of the Guidelines. However, in practice, we need to retain the ability to use other assumptions in order for us to achieve allocations that are broadly proportional to EPNPB, for example:

- In the past, the EDGS have been updated approx. every three years by MBIE; therefore, they may not always be up to date, especially given the current fast-paced evolution of the market. As a result, we recently consulted on variations to the EDGS [27]
- The EDGS have been developed to be used in the investment test, which estimates changes in electricity market costs, not private benefits. Furthermore, the investment test is a decision making tool, not a precise forecast of benefits[28] – so some scenarios may be developed intentionally to explicitly test the bounds of transmission benefits, rather than being a forecast of the future
- The EDGS are not granular enough to be used for our economic analysis without some interpretation. For example, the latest EDGS provide generation expansion scenarios across the country, but we need to know the location with more precision (at least at a regional level).

106. We have included clause 46(2) to clarify that the counterfactual may have a different generation expansion scenario than the factual. This is because the incentive for generators to invest can be affected by transmission investment. For example, transmission investment can unlock an area of lower-cost generation investment (often referred to as dynamic efficiency benefits), reducing the capital and operating costs of generation required to meet load in the future.

107. In contrast, the counterfactual and factual will always use the same demand forecast. In other words, we will assume the transmission investment does not affect the decision for load to connect to the transmission grid. This is a simplifying assumption which limits the scope of the modelling to the electricity market. If we were to assume the demand forecast is influenced by the transmission investment, we would need to significantly expand the scope and complexity of the model – for example, modelling how the electricity price affects consumption and investment decisions in other markets such as transport and industry i.e. a general equilibrium model.

108. Clause 46(3) of the proposed TPM has been included in order for charges to better reflect private benefits for customers that are assumed to exit during the analysis period in some (but not all) scenarios.

109. For example, Table 1 and Table 2 below show a situation where two customers receive benefits from a hypothetical BBI with a five year life, but customer B may exit before the BBI is commissioned and the charges begin, which is reflected in scenario 1. In this

[27] EDGS 2019 Variations Consultation for future scenarios

[28] For example, see reference document #60 Checkpoint 2B resubmission BBC Allocation paragraphs 32-34.

example, it is necessary to model the exit of customer B as a scenario because it significantly affects the existence of customer A's benefits.

110. If we were to base customer B's allocation on its average benefit across both scenarios ($5m), then customer B's annual charge would be lower than its actual proportion of benefits (11.8%) over the life of the investment, if it was to actually exit part way through the BBI's life. Whereas if we based customer B's allocation on the benefit it receives only in the scenario where it remains connected, then its charges would better reflect their actual proportion of benefits. In other words, if we did not adopt this approach, the result is a situation where customer B's BBC is reduced to zero when it exits, plus its BBCs would be scaled down to reflect that it might leave (and not receive benefits thereafter). This would result, in effect, in double compensation for the possibility customer B might leave, and the BBC it pays would understate its relative share of net private benefits.

Table 1: Annual benefits for a hypothetical scenario where a customer may exit

	Scenario 1 – customer B exits before commissioning		Scenario 2 – customer B remains connected		Actual benefits – customer B exits at end of year 2	
	Customer A	Customer B	Customer A	Customer B	Customer A	Customer B
Year 1	$10m	$0m	$0m	$2m	$0m	$2m
Year 2	$10m	$0m	$0m	$2m	$0m	$2m
Year 3	$10m	$0m	$0m	$2m	$10m	$0m
Year 4	$10m	$0m	$0m	$2m	$10m	$0m
Year 5	$10m	$0m	$0m	$2m	$10m	$0m
Total	$50m	$0m	$0m	$10m	$30m (88.2%)	$4m (11.8%)

Table 2: Proportion of charges with and without clause 46(3) for a hypothetical scenario where a customer may exit

	Proportion of charges without 46(3)		Proportion of charges with 46(3)	
	Customer A	Customer B	Customer A	Customer B
Year 1	20%*(25/(25+5)) = 16.7%	20%*(5/(25+5)) = 3.3%	20%*(25/(25+10)) = 14.3%	20%*(10/(25+10)) = 5.7%
Year 2	16.7%	3.3%	14.3%	5.7%
Year 3	20%	0%	20%	0%

Year 4	20%	0%	20%	0%
Year 5	20%	0%	20%	0%
Total	93.4%	6.6%	88.6%	11.4%

111. Clearly, there is no perfect solution to this problem because:

111.1 the Guidelines require allocations to be fixed over time unless one of the adjustment provisions apply (clause iv of the Guidelines),

111.2 the capital components of covered cost must be recovered in total each year (clause 17 of the Guidelines), and

111.3 once a customer ceases to be a transmission customer they can no longer be charged.

112. An alternative solution would be to only base initial allocations on the scenario where the possibly exiting customer stays and apply the substantial and sustained adjustment provision after it leaves. However, in reality:

- the possible exit of one customer can fundamentally affect the benefits and beneficiaries of a BBI, and so may need to be included as a scenario in order to reflect the full expected beneficiaries of a BBI, and
- customers often advocate for investments to be made before the substantial and sustained event occurs, which is economically rational if the private benefits they would receive from the BBI are significantly greater than their charge, even if the scenario in which they receive benefits never eventuates (i.e. they receive significant option value from the investment).

113. CUWLP is a good example of this situation. In our 2020 consultation on CUWLP, Meridian and Contact[29] advocated for CUWLP to proceed given the strong possibility of Tiwai exiting in 2021. Clearly, given their support for the project and knowledge of the forthcoming BBC, Meridian and Contact considered the private benefits of CUWLP to be larger than the charge they expected to receive under a benefit-based charge. However, since our consultation, it is now unclear if and when Tiwai will exit, but Tiwai continues to receive benefits from CUWLP until the time Tiwai exits.

114. On balance, given the practical realities of investment decisions made under uncertainty, we consider 46(3) allows us to better comply with clauses iv and 8 of the Guidelines, which require charges be in proportion to expected benefits.

[29] Meridian submission and Contact Energy submission

9 Price-quantity standard method step 1: Market benefits

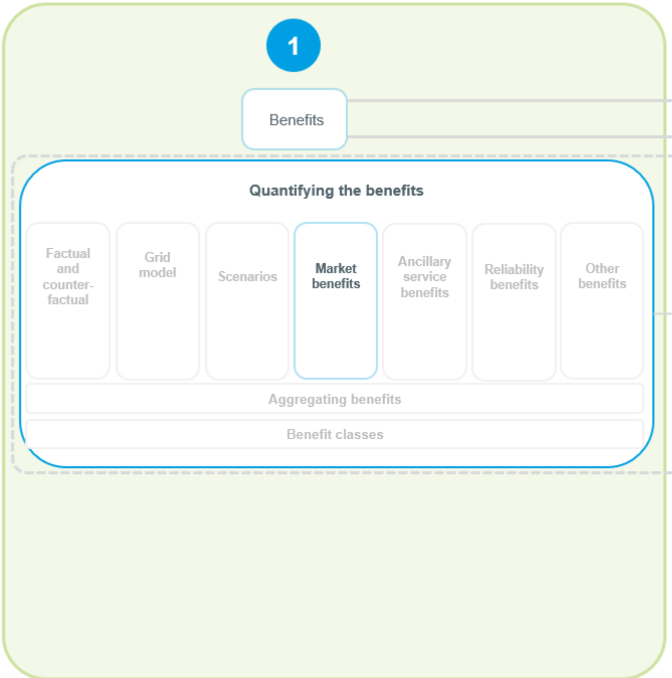


Figure 9 Price – Quantity standard method step 1 Market benefits

9.1 Our proposal

115. We must use a wholesale market model to model the prices, quantities and changes in price and quantity in the wholesale market for electricity between the market BBI's factual and counterfactual under its market scenarios and based on its investment grids. The modelling must cover each year of the market BBI's standard method calculation period (50(3)).

116. In accordance with its definition in the proposed TPM and figures 10 and 11 the wholesale market model:

- models a market BBI's factual, counterfactual and market scenarios
- assumes suppliers offer prices based on their marginal variable costs of supply
- assumes perfectly inelastic demand up to one or more estimated costs of self-supply that are the same for all demand types
- applies least-cost dispatch to the market BBI's factual, counterfactual and market scenarios to model the change in prices and quantities in the wholesale market for electricity between the market BBI's factual and counterfactual
- uses the BBI's factual, counterfactual and investment grid assuming a security-constrained grid based on the constraints included in the investment grid (see definition of investment grid).

117. Private benefits received due to changes in the prices and quantities in the wholesale market will include wealth transfers from one party to another, but not include the cost of the transmission investment itself. This is illustrated by the below diagrams (figures

10 and 11 of the proposed TPM), showing a stylised graphical representation of an electricity market's supply and demand curves before (S) and after (S') a shift in the generation supply curve due to a transmission upgrade. Figure 10 shows a shift that results in the price changing but no change to the total quantity of electricity consumed or produced, and figure 11 shows a shift that increases the quantity of electricity consumer and produced. Consumers are willing to pay for electricity at any price up until some maximum price (P_{max}), at which point no consumers are willing to pay for electricity.

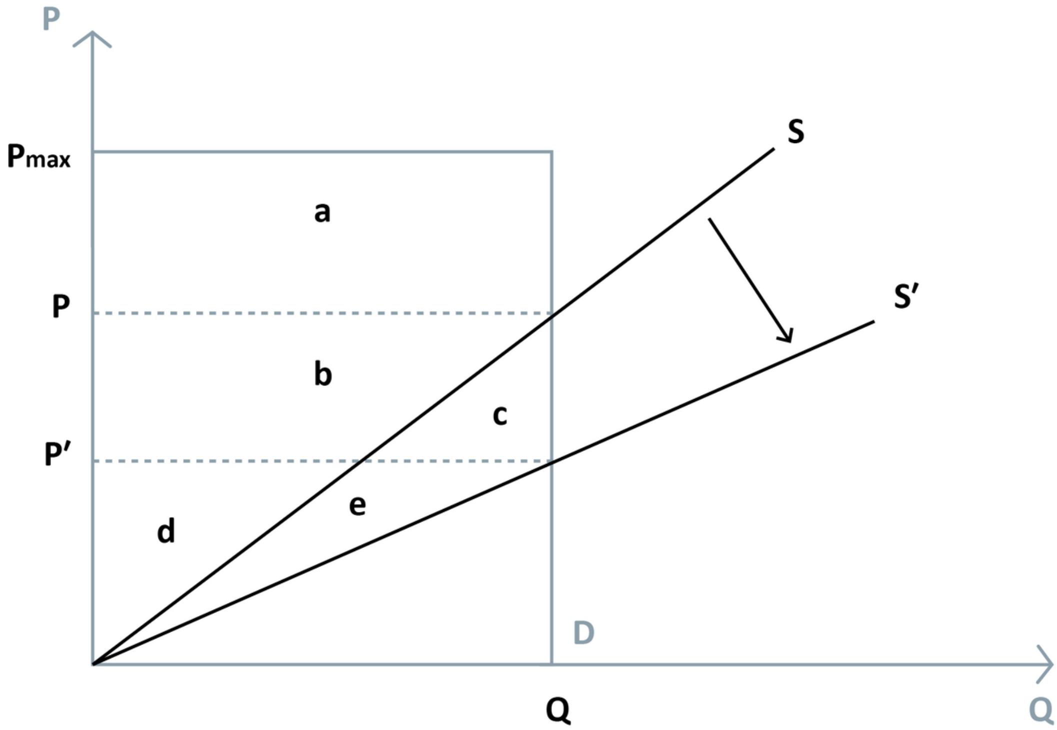


Figure 10 Proposed TPM, figure 10

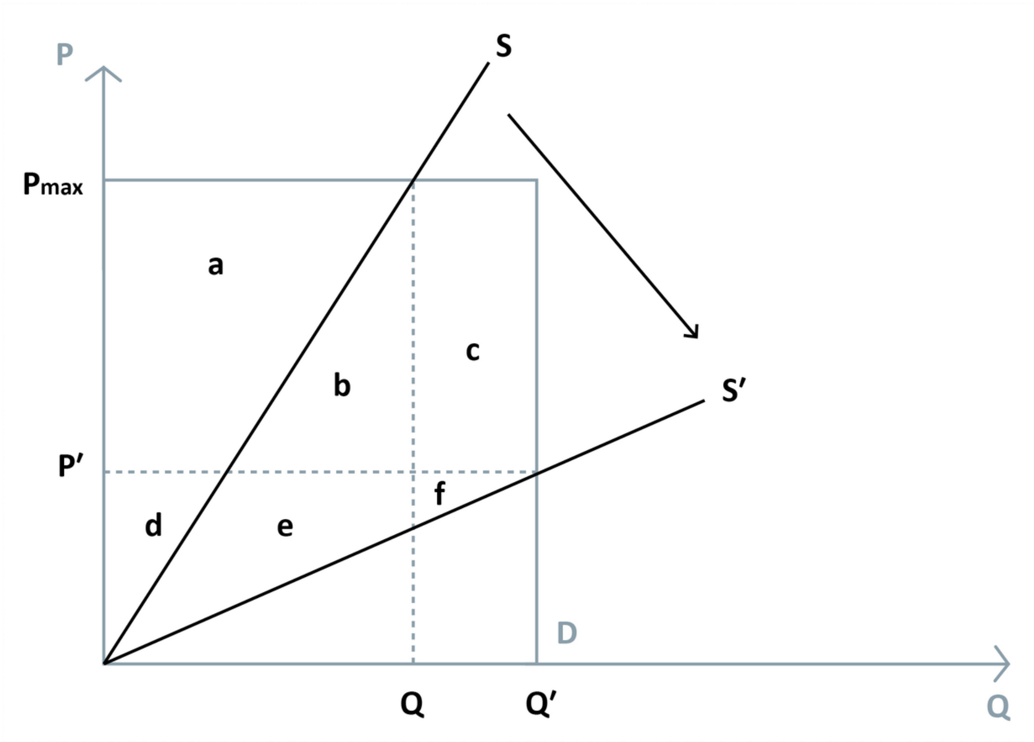


Figure 11 Proposed TPM, figure 11

118. In accordance with clause 50A, where we consider this clause will result in allocations that are broadly proportional to EPNPB, we will determine allocations for the benefitting regions based on the quantity of generation and load in each of these regions during the periods the BBI is providing its primary benefits, plus any increase in quantity due to the BBI. The modelled regions are determined based on the GXPs/GIPs that have a decrease/increase in price based on the results of the wholesale market model, including any adjustments made under 50(5). If needed in order to combine market benefits with reliability, ancillary service, and other benefits, we will calculate regional NPB based on the total EPNPB for all beneficiaries and the allocations to each region determined under clause 50A. The CUWLP case study illustrates this method in practice.

119. If clause 50A is not used, under clause 50B we will use the wholesale market model and any adjustments to the prices under clause 50(5) to:

- determine regions based on the GXPs/GIPs that are expected receive similar changes in price, and
- calculate regional NPB.

120. Under clause 50B, in the illustrative wholesale market model in figure 10—

- the expected market benefit or disbenefit for the regional demand group is equal to the modelled change in consumer benefit, being:

factual	counterfactual	change in consumer benefit
a + b + c	a	b + c

- the expected market benefit or disbenefit for the regional supply group is equal to the modelled change in producer benefit, being:

factual	counterfactual	change in producer benefit
d + e	b + d	e - b

- In the illustrative wholesale market model in figure 11—
- the expected market benefit or disbenefit for the regional demand group is equal to the modelled change in consumer benefit, being:

factual	counterfactual	change in consumer benefit
a + b + c	0	a + b + c

- the expected market benefit or disbenefit for the regional supply group is equal to the modelled change in producer benefit, being:

factual	counterfactual	change in producer benefit
d + e + f	a + d	e + f - a

121. When clause 50B is used to quantify regional benefits, any changes in the modelled loss and constraint excess (LCE) will be included in the calculation of consumer and producer benefits (50B(4)(b) and 50B(5)(b)).

9.2 Rationale – 50A and 50B methods

122. In our original options consultation, we proposed the 50B method using the outputs of our wholesale market model to calculate regional benefits.

123. We received support for and objections against our approach to quantifying market benefits in submissions to our options consultation.[30]

124. Mercury "*agrees that the model should be determined on a least-cost optimisation basis*". Unison/Centralines "*agree that reliance should be placed on simplified models of generator dispatch based on generic assumptions about costs.*"

[30] Refer submissions and cross-submissions TPM Development Options consultation process

125. However, Vector disagreed with our approach: "*We consider all the approaches attempting for forecast market benefits from transmission investment is subject to significant estimation risk.*" Similarly, Creative Energy Consulting (CEC) for Trustpower had several concerns relating to the quantification of market benefits: "*CEC believe that it is not possible to separate "accuracy" from "transparency": what ultimately matters is not whether the benefits allocation turns out to be accurate but whether transmission customers believe the results are "reasonable and plausible… Energy price modelling is a critical component of the BBC model and fundamental to its transparency and outcomes. As discussed above, transparency requires that model outcomes are intuitive and aligned with private modelling results. In my view, the cost-based modelling proposed by TP will achieve neither requirement*."

126. We acknowledge the inevitable tension between complexity, accuracy and transparency for a methodology attempting to allocate costs in accordance with private benefits and consistent with the investment test. It is something we have been acutely aware of in developing the new TPM. The Guidelines acknowledge that practical matters such as simplicity and transparency are important considerations for the BBC (clause 1(b)). As indicated in our 2B resubmission,[31] we have sought to balance this tension by proposing to determine regional beneficiaries based on the price outputs of the market model, and using the quantities during periods of benefit to determine the allocations between these regional beneficiaries. The intent of using the quantities during periods of benefit is to produce allocations that would be observed if the price change due to a BBI was the same for all regional beneficiaries (and ignoring operational costs for generation where there is a change in the quantity of generation).[32] Section 9.9 expands on our rationale for choosing this simplifying approach, and the CUWLP case study is an example of how this will work in practice.

127. Furthermore, to limit the number of inputs that are contested at the time of the investment, we are proposing the use of an assumptions book which is consulted on periodically rather than for each investment.[33] This consultation approach should increase customers' confidence in soundness of the BBC allocations.

128. We note our proposed approach will not remove the possibility of contention and lobbying given the allocations are based on future scenarios rather than backward looking metrics based on measured data. Clause iv of the Guidelines is clear that the BBC be based on forward looking (i.e. expected) benefits, and that there should be a strong link between the assumptions used to make the investment decision and the charges for that investment (clause 23 of the Guidelines). Given this context, we recognise the price-dimension is relevant for setting regional beneficiaries. Therefore, under clause 50B of the proposed TPM, we have allowed for different price changes to

[31] Reference document #60 Checkpoint 2B resubmission BBC Allocation

[32] Under 50B, where a generator is benefitting from the BBI because of more generation in the factual, their benefit will be offset by any operational costs, which is ignored in 50A. This is a reasonable simplifying assumption under 50A because we consider it possible that our wholesale market model under-estimates market prices due to us not modelling losses and outages and by assuming a perfectly competitive market (among other simplifying assumptions), which would result in an under-estimate of generator benefits under 50B. In other words, neither method is perfect in this respect – 50B may under-estimate generator benefits where there is an increase in generation in the factual, and 50A may overestimate generator benefits in the same situation.

[33] This is broadly analogous to the adoption of Input Methodologies under Part 4 Commerce Act which are consulted on periodically (every 7 years) separate to the Commerce Commission's price-quality regulation determination process.

apply to different beneficiaries informed by, but not necessarily based solely on the outputs of our wholesale market model (e.g. where market price outputs are not fully reflective of the capital cost of new modelled generation investment, which may be important when assessing dynamic efficiency benefit) (clause 50(5)).

129. We note there will be a strong link between the benefits and the modelling used to inform the investment decision using both the 50A and 50B methods:

- the forecasts of supply and demand will be based on the assumptions we use for the investment test
- the beneficiaries will be identified based on the results of our market modelling, which will identify how and when an investment is benefitting the beneficiaries – for example, the times when a constraint is binding.

130. In response to our 2B resubmission,[34] the Authority requested "If Transpower decides to propose the post-processing adjustments to forecast market prices under the standard method framework for assessing market benefits outlined in its preliminary proposed TPM, information on the following:

a) *Is there merit in including additional criteria or process steps in the proposed TPM to guide the adjustment process? For example, should there be safeguards in the adjustment process to protect against the risk of suppressing an efficient price signal (which would be counter to the intention of the adjustment process which is to only limit the undue influence of input assumptions unrelated to expected positive net private benefits)?* ***Transpower response:*** We agree that, over time, there should be more specificity on the process we will follow and potentially additional criteria to determine when/when not to apply this simplifying assumption. We intend to document these processes in the assumptions book.[35] As we gain experience with the BBC, we expect to add more situations to the assumptions book. Furthermore, we have added a requirement that 50A will only be used where we consider this will result in allocations that are broadly proportional to EPNPB (clause 50A(1)).

b) *"How significant will these adjustments to allocations under the standard method be? We expect insights from case studies to help us and other stakeholders understand this."* ***Transpower response:*** Table 3 (Section 9.9) provides an indication of the potential magnitude: the unadjusted outputs result in an allocation to generation of 7%-28%, the CUWLP case study allocates ~25% to generation.

c) *"Specific examples of how the adjustments process is intended to increase the transparency of the price-based model and how it might help stakeholders understand the modelling results (as indicated in Transpower's resubmission at para 35)."* ***Transpower response:*** the adjustments are intended to promote transparency because – as demonstrated in the CUWLP case study – we can use a simpler proxy to determine allocations based on the quantity of generation and load during periods of benefit. While still an output from a

[34] Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A - D. paragraph A7

[35] See Section 17 for more detail on the assumptions book.

complex model, we expect this proxy will better allow customers to understand their charges and the key assumptions we are making that result in the BBI passing the investment test (e.g. load and generation forecasts, scenario weightings). Ultimately, for many BBIs, we consider these type of assumptions are more relevant to a BBI passing the investment test than changes to wholesale market prices either side of a constraint, which may only be relevant for determining private benefits. Given one of the Authority's key outcomes for the BBC is to incentivise scrutiny of the investment test from those who are being charged for an investment,[36] it seems pertinent to base the methodology on the assumptions that are most likely to affect the outcome of the investment test – especially where those assumptions are more easily critiqued by the large proportion of our customers who are not participants or experts in the wholesale market (e.g. distributors).

d) Examples of the types of information Transpower would make available to transmission customers to allow them to understand the basis on which their BBCs have been set (as required by cl 6 of the guidelines). ***Transpower response:*** the CUWLP case study shows an example of the information we could make available to customers. Over time, we expect to evolve our approach to information provision based on the needs of customers.

9.3 Rationale – constraints

131. Transmission security constraints usually begin limiting transmission flows before transmission circuits run out of physical capacity. We propose to apply transmission security constraints to the wholesale market model consistent with the investment grid as described in Section 7 of this chapter.

9.4 Rationale – max price for load and inelastic demand

132. Like any market, there will be some price above which consumers would prefer not to consume (usually higher than the cost of generating electricity). In practice, this means the prices produced by the dispatch model will never be higher than this maximum price, which we refer to as Pmax in the proposed TPM. Below Pmax, as a simplifying assumption, demand will be assumed to be inelastic.

133. While we acknowledge different load types are likely to have a different willingness to pay, we have insufficient information to use a different willingness to pay for different loads:

- While loads may respond to high prices if they occur infrequently, they are likely to hedge any exposure to high wholesale market prices if they occur frequently. Consequently, how a load responds to market price will change over time. There may be other reasons an individual customer's willingness to pay changes over time in hard to predict ways, such as changes to the profitability of their business e.g. for large industrial customers.

[36] For example, see reference document #3 2020 Decision executive summary.

- In reality, the load beneficiaries of an investment will be sensitive to a load's willingness to pay compared to the absolute market price. Given the limitations of estimating absolute price over 20 years, our methodology is primarily focussed on estimating changes to market prices in a future with and without a transmission investment, not on determining absolute market prices.

134. Furthermore, we are concerned that it would be very difficult to verify if one load customer had a lower willingness to pay than another given the conditions of system stress we model occur very infrequently. Rather, we think willingness to pay should be based on the cost of self-supply, which is likely to be similar for all customers.

135. Finally, we understand the Authority made a similar assumption when producing pricing for the seven historical investments in Schedule 1.[37]

9.5 Rationale – Pmax set at the cost of self-supply

136. An alternative to assuming Pmax based on the cost of self-supply would be to assume large-scale generation is built to avoid scarcity prices (e.g. by setting Pmax at the LRMC of new generation). There are several reasons we consider this assumption unsound, or at least not applicable for all BBIs:

136.1 New large-scale generation often isn't realistic in every situation as many areas of the grid have no consented generation projects that can be commissioned in time to supply load. Assuming a hypothetical generator is commissioned just in time could result in situations where the assessment of benefits does not reflect the real consequences of us not investing – e.g. very high prices in the wholesale market reflecting scarcity.

136.2 We already account for known, committed generation projects in the short-term assessment of the need of an investment, and, in the longer term, as modelled projects in our expansion scenarios.

136.3 An erroneous assumption that a hypothetical generator will arrive would not be consistent with the investment decision, which – for a project undertaken to avoid scarcity prices – would be made to meet our obligations under the deterministic arm of the GRS.

136.4 Generation investment is lumpy – in other words, it is unlikely that generation will appear in the right place and of the right size to perfectly avoid all scarcity. Scarcity would need to be regular enough to significantly affect average prices in order to incentivize a generator to enter a market to take advantage of the high prices.

136.5 Similarly, with the penetration of intermittent renewables increasing, a key benefit of transmission may become the balancing of intermitted generation across the grid to avoid scarcity. Assuming all scarcity prices are priced at the LRMC of generation would ignore the operational realities of generation that is not dispatchable.

[37] Document reference #1 2019 Issues paper. For example, paragraphs 43-53 in Appendix H did not discuss the use of a different price offer for different grid exit points.

9.6 Rationale – prices based on marginal variable costs of supply under 50B

137. In the wholesale market, offers are provided by participants for each trading period and the optimisation problem is solved in real-time by the system operator's Scheduling, Pricing and Dispatch tool (SPD).

138. However, to forecast the market benefit of transmission projects we need to consider this optimisation problem over a much longer period of time (typically 20 years into the future). We consider it is not reasonable or practicable to use historical offers as the basis for future prices because to do so we need to consider demand and generation behaviour in very different scenarios than the recently observable past.

139. For long-term power system modelling, it is common to assume thermal and must-run generation will be offered at each generator's operational cost, being the sum of various variable costs including fuel costs, variable operational and maintenance costs, and carbon costs. However, in reality, prices in the wholesale market are the result of a complex interaction of a multitude of factors, including:

- The exertion of market power by generators in a market that is not perfectly competitive
- The load and generation portfolio of each market participant, so offers at an individual station may be influenced by this portfolio
- Regulation and policy – e.g. an energy-only market structure.

140. This complexity acts as a multiplier on the uncertainty of the various factors in an ever-changing environment. In short, trying to forecast prices over decades with a high level of accuracy is very difficult given the number of variables.

141. In our original options consultation, we proposed the 50B method using the outputs of our wholesale market model to calculate regional benefits, based on the assumption that market prices are equal to the marginal variable cost of supply. Submitters that specifically commented on this design decision generally supported this assumption.

142. Meridian "*agree(s) that any attempt to overcome model limitations (for example to model trading behaviour or regulations and policies) would add significant complexity, entail many discretionary assumptions, result in opaque and contentious cost allocations, and threaten the durability of the TPM. Meridian prefers the simpler, rules-based approach to allocate benefits*." Unison/Centralines "*agree that reliance should be placed on simplified models of generator dispatch based on generic assumptions about costs*."

9.7 Rationale – interpretation of private benefits under 50B

143. When we undertake cost-benefit analysis, we assess reductions in electricity market costs against the cost of investment. In other words, we assess net changes in economic surplus in the electricity market and ignore wealth transfers between parties in the market e.g. between loads and generators. These are often referred to as efficiency benefits. We do not typically identify who these benefits will be received by – this is a new concept introduced by the Guidelines. The Guidelines are clear that cost

allocation must be based on the private benefits customers receive from transmission investment. However, "net private benefits" is not precisely defined in the Guidelines:[38]

> *"**net private benefit** means, for a designated transmission customer and with respect to a specific **investment**:*
>
> *a. the value of the private benefits which are aligned with **electricity market benefit or cost elements** that arise from the 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 aligned with **electricity market benefit or cost elements** (but excluding the cost of the **investment** itself) that arise from that **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 private benefits or private costs where those benefits or costs are significant and result from the benefit-based investment."*

144. The Authority's TPM 2019 Issues Paper states:[39]

145. "*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). 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. 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*."

146. This definition is clearly different to an assessment of efficiency benefits; however, both changes in private benefits and efficiency benefits can be derived from our modelling, with some simplifying assumptions. In practice, this means we could use our modelling to determine efficiency benefits for the purposes of making investment decisions, and also identify changes in private benefits for the purposes of cost allocation through the BBC.

147. Therefore, we consider our interpretation described in Section 9.1 to be consistent with the Guidelines and related to the benefits we assess through the investment test.

148. Most submitters did not comment on the interpretation of private benefits.[40] Of those who did:

148.1 Meridian agreed with our interpretation.

148.2 Tilt thought *"calculating benefits according to the operational cost of generation only could result in flawed outcomes and perverse incentives."* We have considered this issue in the section below.

38 Reference document #4 Guidelines, Clause 69 'Interpretation', definition of **net private benefit**.
39 Document reference #1 2019 Issues paper, B.110, page131.
40 Note, this interpretation has been rephrased since the options consultation to more clearly state our interpretation.

148.3 CEC for Trustpower identified the importance of rentals: *"The rental is the surplus in spot market settlement arising from congestion prices and marginal loss factors.... Given this central role, it is anomalous that the proposed TPM makes no mention of it."* Where explicitly including assuming different price changes to different beneficiaries under 50B, we agree it is relevant to account for the modelled (not actual) loss and constraint excess (**LCE**) in the allocation because in the absence of transmission investment, there will be more LCE. Therefore, a transmission investment will reduce LCE (a disbenefit), which will partially (but never fully) offset the benefits of the investment from reducing market prices.

9.8 Possible inefficient incentives for generation investment when using 50B

149. In its submission to our options consultation, Tilt suggested BBCs will be higher for low-operational cost generation technologies under a price-based standard method that only considers SRMC: *"This approach will inappropriately favour a higher operational cost generator, with quantified benefits under the proposed approach being less than compared to a low operational cost generator, even if the two generators have similar long run marginal costs (LRMC). The BBC should not be looking to prop up high operational cost generators via reduced transmission charges, nor should it result in low operational cost generators paying a higher proportion of a transmission investment simply due to the nature of their CAPEX/OPEX splits."*

150. We originally responded to this by agreeing that the capital cost of generation connecting after the commissioning of the transmission investment should be included in the calculation of generator's surplus to avoid a bias against low-operational cost generation plant. To clarify our response, as a general rule, we agree that two generators that do not yet exist and are identical except for their CAPEX/OPEX split should have the same charge. This is because, in the long-run, two generators with the same LRMC (and the same operating characteristics and output) will derive the same benefit from the market.

151. However, for generators that already exist and therefore for which are sunk investments with respect to a new transmission investment, conceptually, a price-based BBC has the potential to result in higher charges for low operational cost generation. This is because low operational cost generation (e.g. wind, run-of-river hydro) is more likely to be operating in the counterfactual than higher cost generation (e.g. gas peaking plant), so will receive a greater change in benefit (and therefore higher proportion of the benefit-based charge). This result is illustrated by the following diagram,[41] which shows how a low operational cost generation has a larger change in benefit for the same increase in price because the high cost generator gets dispatched-off in the counterfactual.

[41] The diagram shows the supply curve for a particular region that has a surplus of generation, not for the whole market (hence why this transmission investment increases the price in that region).

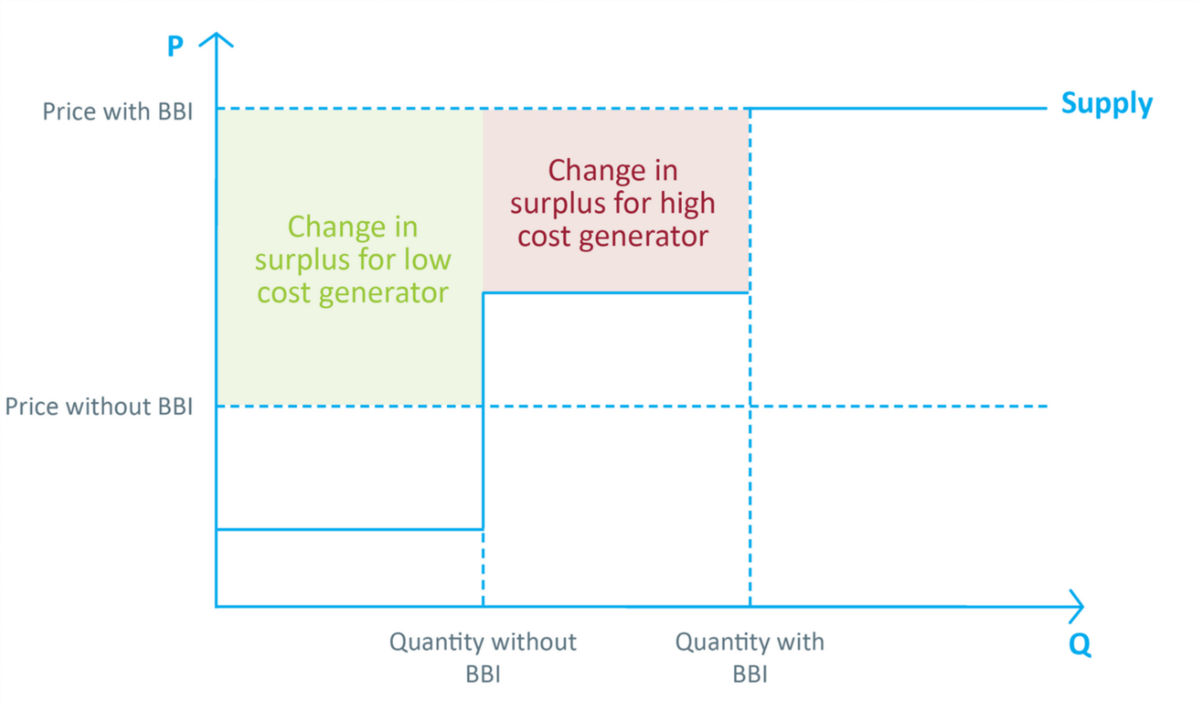


Figure 12 Generation benefits for two hypothetical generators

152. In the short-term, we have no reason to think this approach will be distortionary or economically inefficient because the fixed costs of all existing generation stations are sunk costs, and therefore should not affect operational decisions. However, in the long-term, investors in low operational cost technologies may take into account the potential that they will receive higher transmission charges if there is a new BBI commissioned after their investment has been made i.e. at which point their new generation station will be considered sunk under 50B. This effect may introduce an incentive towards investment in higher operational cost generation plant (all else being equal).

153. Having considered the issue further, we now think sunk capital costs should not be used as a cost in the definition of generator benefits for new or existing generators, because:

- of the practical difficulty of determining the appropriate fixed cost assumptions for existing generator stations that have been connected to the grid for several decades
- including capital costs in the generator benefits of an existing generator would not change their net-private benefits, because the capital cost would exist in both the factual and counterfactual scenarios
- the adjustment process when a new customer enters assumes a new generator should has the same annual benefit as an identical existing generator.

154. In response to this issue, we have identified the following options under 50B:

- Aggregate all generators in a benefitting region into a single group, which would ensure that identical new and existing generators have the same annual

BBC, and that two new generators that are identical except for their CAPEX/OPEX split would also have the same annual BBC

- Do not attempt to correct the issue, which – if combined with a method that assumes new generators have the same annual benefit as identical existing generators – would introduce the potential for the incentive described above.

155. In the Authority's response to this issue raised through checkpoint 2B, it "*consider[s] that Transpower has identified an issue that needs to be considered further. We will need to undertake further work to form a view on which of Transpower's proposed options (or potentially, another option) are appropriate for addressing the issue in line with the guidelines and our statutory objective. This includes understanding the extent of the undesirable incentive. We expect to work with Transpower further on this issue. If Transpower has not yet been able to form a view on the magnitude of any perverse incentive by 30 June, we would be comfortable for Transpower to not include drafting attempting to address this issue in its proposed TPM and to instead acknowledge the issue might require further work.*"[42]

156. We consider the TPM gives us the flexibility to proceed with either of the two options above.

9.9 Other standard method options for quantifying market benefits we considered

157. In developing our proposal for the standard method, we also considered alternative options. In particular:

- a methodology based on vSPD,[43] similar to the Authority's Schedule 1 allocations method for historical projects
- a power flow-based sensitivity factor methodology for identifying beneficiaries
- a price-based method that uses the prices directly from the output of our wholesale market model for all market BBIs, as originally proposed in our options consultation and checkpoint 2B submission.

vSPD

158. We concluded that vSPD – on its own – would not be a viable methodology for forecasting benefits 20+ years into the future and would not produce robust results. This is because, for example, vSPD (and SPD) was designed as a dispatch model that receives generation offers to sell energy into the market as an input. It was not designed to forecast dispatch, prices, and benefits decades into the future. vSPD could be used in combination with historical offers to estimate future benefits. However, historical offers are unlikely to be accurate representations of a generator's willingness to supply in the future, including because when we undertake cost-benefit analysis we often model very different states of the grid than the recent past. Examples include step-changes to demand or generation, different transmission constraints, higher carbon prices and fuel costs, and a large range of hydrological

42 Reference document #56 Letter from EA: Checkpoint 2B submission, page 7.

43 vSPD is the Authority's replica of Transpower's Scheduling, Pricing and Dispatch (SPD) model.

scenarios. All of these factors can have a significant impact on offers from individual generators at any given point in time.

159. Our methodology is different to vSPD because, rather than using historical generator offers as inputs to the model, it creates generator offers based on assumptions about operational costs. To create offers for hydro generators, our methodology models the hydrological network and inflows to storage lakes. We consider this to be a more robust and accurate methodology.

FLOW-based method

160. We also considered a power flow-based method, such as the power flow-based sensitivity factor[44] method.[45] We recognise our proposed standard method is complex, and a flow-based method that reduces the degrees of freedom in the allocation would be likely to be more transparent, helping customers to meaningfully engage with the BBC.

161. However, we have dropped consideration of the flow-based method. In practice, we found the additional step of calculating power flow-based sensitivity factors based on the outputs of our wholesale market model added complexity that is unnecessary given we now consider we can mitigate our concerns (to the extent possible within the Guidelines) using our proposed approach.

162. Furthermore, we received clear feedback from the Authority *"consider[s] that the flow-based method's apparent inability to capture value differences (conceptually at least) means that it is likely to be less capable of assessing benefits"* and a price-based method *"is more likely to produce a proposed TPM which is consistent with the guidelines and with our statutory objective."*[46]

163. We consider our proposed approach (50A of the proposed TPM) does not suffer from these problems, because:

    163.1 The flow-based method resulted in an allocation that was (close to) 50:50 for generation and load for the CUWLP BBI. Our proposed method allocates based on the quantity of generation and load benefitting from the BBI – e.g. for CUWLP, ~25% to generation and 75% to load, which – for this BBI – we consider better reflects EPNPB than a 50:50 allocation between generation and load.

    163.2 the proposed TPM requires we only use 50A where we consider it will result in allocations that are broadly proportional to EPNPB, such as the CUWLP case study.

Original price-based method

164. In our options consultation and 2B submission, we proposed a price-based method that uses the price outputs directly from our wholesale market model. In our 2B resubmission, we highlighted the need to adjust prices outputs where we considered them to be sensitive to input assumptions and therefore would not be broadly

---

44 This is sometimes called a flow distribution factor (or shift factor).

45 For more information on the FLOW-based method, refer to Checkpoint 2B submission (reference document #48).

46 Reference document #56 Letter from EA: Checkpoint 2B submission, page 2.

proportional to EPNPB. In its response to our 2B resubmission, the Authority requested "*A more comprehensive description of the problem the proposed post-processing adjustments to forecast market prices under the standard method for assessing market benefits seeks to address (e.g. with reference to case studies).*"[47] This section responds to that request.

165. To clarify our proposal, we note there are other reasons for not using the market prices directly out of the wholesale market model – in particular, where market prices are not fully reflective of the capital cost of new modelled generation investment, which may be important when assessing dynamic efficiency benefits, hence why we have allowed for price adjustments under clause 50(5) of the proposed TPM.

166. That said, a key motivator is the sensitivity of the outputs of the wholesale market model to inputs assumptions. We consider these price outputs to be too sensitive to uncertain input assumptions to be relied upon in a fixed allocation methodology that is used to allocate charges over decades in all situations. Importantly, we have found private-benefits are more sensitive than the changes in electricity market costs measured by the investment test in some situations. In other words, an assumption that may not need to be known with precision for the investment test may be very important for a private benefit assessment.

167. For example, table 3 below shows the results of three scenarios[48] analysed using the original price-based method for the Clutha and Waitaki Lines Project (CUWLP) during the analysis period 2025-2029.

Table 3: Results from indicative modelling for the CUWLP BBI for the 2025-2029 modelling period

	Environmental			**Disruptive**			**Disruptive – generation expansion variation**		
	Factual (F)	Counter factual (CF)	F- CF	F	CF	F-CF	F	CF	F-CF
Thermal + deficit costs **$m**	690	920	230	830	1,080	250	1,150	1,420	260
Time-weighted price BEN220 **$/MWh**	31	61	-30	45	71	-26	68	85	-17
Time-weighted price MAN220 **$/MWh**	30	21	9	44	26	18	68	43	25

47 Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A - D. paragraph A7
48 All assuming Tiwai leaves at the end of 2024.

	Environmental			Disruptive			Disruptive – generation expansion variation		
Positive npb[49] to load (PV 2023 **$B**)[50]			4.1 (93%)			3.5 (86%)			2.1 (72%)
Positive npb generation (PV 2023 **$B**)			0.3B (7%)			0.6B (14%)			0.8B (28%)

168. The principle difference between the three scenarios are the demand forecast and generation expansion assumptions. All three scenarios have the same beneficiaries (generators electrically south of Cromwell and loads electrically north of Twizel).

169. The most important costs that determine the benefit of an investment under the investment test are thermal costs (including emissions costs), and deficit costs (i.e. unsupplied demand due to a lack of transmission or generation). While the absolute thermal and deficit costs are very different across the scenarios, the change due to the investment is very stable across the three scenarios: ranging from $230m - $260m. If these scenarios fully described the range of possible future scenarios relevant to the investment, we could be highly confident in the total benefits without having to take a precise view on which scenario is most likely.

170. However, the proportion of positive net private benefits to load and generation are much more sensitive – varying from as low as 7% up to 28% in these scenarios. A significant contributing factor to these results is the average price at which the market settles in the factual – when the market settles at a higher price, the proportion of positive net private benefits tends to be higher for generation. The price at which the market settles is a complex interaction of many variables – e.g. the generation fleet, hydrology, generation capital and operating costs, and demand. The market has little history of such a major oversupply situation as Tiwai leaving, which exacerbates the uncertainty associated with this case study.

171. Getting consensus from stakeholders on the appropriate market price assumptions to choose for a given BBI is likely to be challenging, even when all parties agree the investment is worthwhile and their private benefits will exceed their charges. For example, the feedback and commentary in relation to the Climate Change Commission's estimates, based on highly sophisticated and complex modelling, of wholesale electricity prices highlight some of the inevitable challenges with forecasting prices with high precision.[51]

172. If the approach used in the TPM does not recognise the sensitivity of allocations to input assumptions, especially where these inputs assumptions do not affect the result of the investment test, then the durability of the TPM will likely be affected due to

49 npb = net private benefits, and note unit change for the dollars, from $m to $B.
50 Without an adjustment for the constraint excess, which would not materially change the conclusions drawn from this table.
51 For example, see paragraphs 117-122 of Energy Resources Aotearoa's Submission on the Climate Change Commission's Draft Advice for Consultation: https://www.energyresources.org.nz/dmsdocument/171

lobbying by parties who want an investment to proceed but wish to receive a smaller proportion of the BBC.

173. In response to our 2B resubmission, the Authority requested "*Consideration of reasonable alternative options to our proposed post-processing adjustments to forecast market prices under the standard method framework for assessing market benefits*." [52]

174. Rather that adjusting prices in post-processing, we considered an alternative to this approach: running a large number of scenarios and taking the average of these scenarios. However, our existing market modelling is already computationally and resource-intensive, and like for all complex models, we have found the models require checking to ensure they are producing reasonable results, and often require modification to inputs and re-running of the models where we consider the outputs to not be reflective of private benefits. Adding more scenarios would make this more difficult, to the point of impeding transparency for us and our stakeholders. We consider the cost associated with administering and complying with a TPM that modelled many different scenarios would be disproportionate to the economic benefits of precision (in accordance with clause 1(b) of the Guidelines). Therefore, we have ruled this out as an option.

10 Price-quantity standard method step 1: Ancillary service benefits

175. This section describes our proposal for quantifying ancillary service benefits.

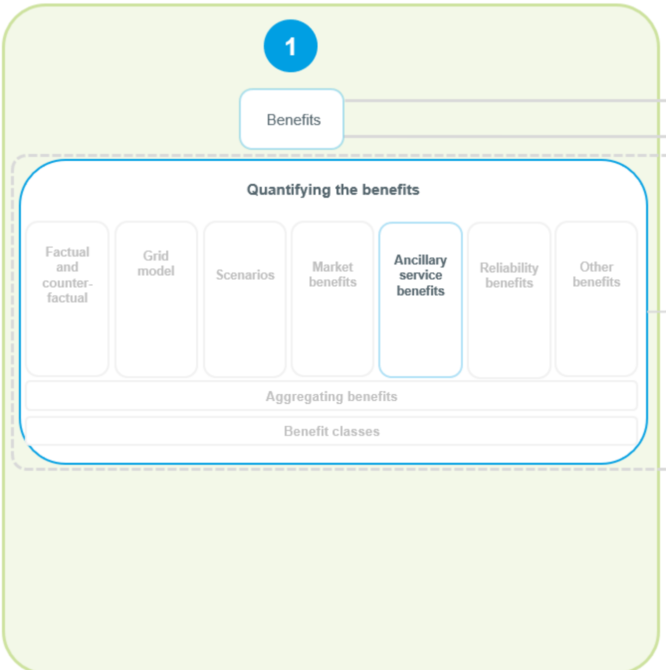


Figure 13 Price – Quantity standard method step 1 Ancillary service benefits

52 Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A - D. paragraph A7

10.1 Our proposal

176. Clauses 51 of the proposed TPM allows for Transpower to include ancillary service benefits as a benefit to be factored into allocations (frequency keeping, reserves, and voltage support).

10.2 Rationale

177. Occasionally, a transmission asset may reduce ancillary service costs – for example, the HVDC Pole 3 investment reduced the quantity of frequency keeping and reserves required procured from generators. Therefore, we have allowed for these benefits in the TPM, although we don't expect them to be used frequently. For that reasons, we have not specified a detailed methodology for quantifying these benefits.

11 Price-quantity standard method step 1: Reliability benefits

178. This section describes our proposal for quantifying reliability benefits.

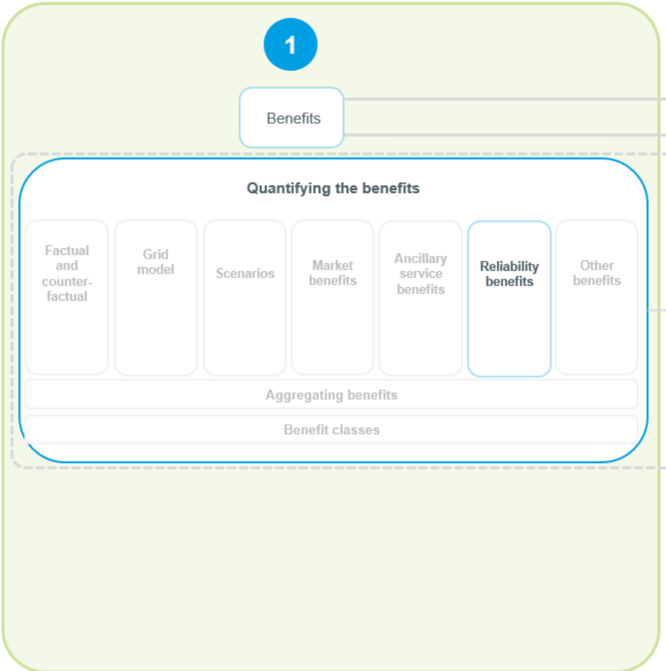


Figure 14 Price – Quantity standard method step 1 Reliability benefits

11.1 Our proposal

179. For the purpose of the TPM, reliability benefits are where there is a material reduction in unserved energy due to an outage or other event or group of events affecting access to transmission services (see definition of reliability BBI in the proposed TPM). As discussed in Sections 5.3 and 9, for the purpose of the TPM we are classifying avoided scarcity prices as a market benefit.

180. The diagram below illustrates how we propose to quantify reliability benefits (52(3)).

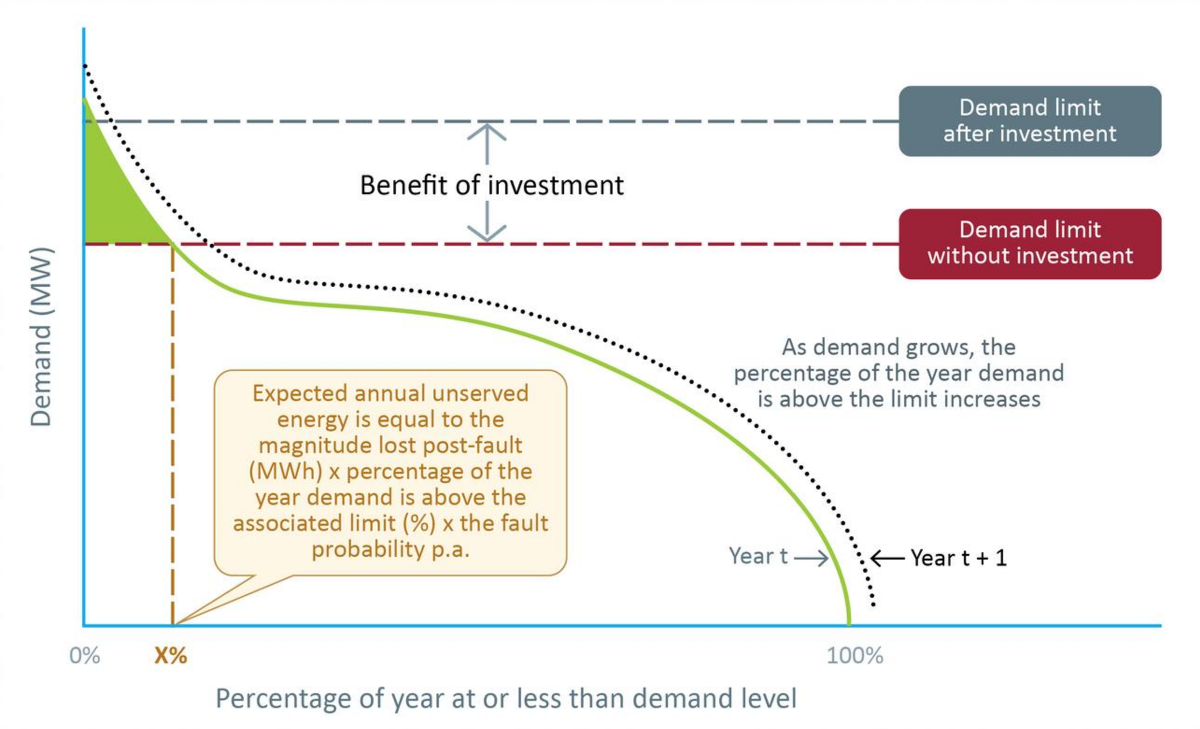


Figure 15 Quantifying reliability benefits

181. The key features of the method are:

181.1 The capability of the transmission system before and after investment is represented by system limits. These limits represent the point above which the system is at risk of interruption following a system fault. System limits are produced by detailed engineering modelling of the capability of the power system.

181.2 The probability of being above a system limit is represented by a load duration curve, which is the load throughout the year ordered from its highest level (i.e. the peak) to the lowest (i.e. the trough).

181.3 The magnitude of expected unserved energy is calculated by the probability of load being above the limit multiplied by the probability of a fault multiplied by the amount of load or generation expected to be disconnected following a fault.

181.4 The cost of unserved energy ($) is equal to the magnitude of unserved energy (MWh) multiplied by the value of lost load (VoLL) or value of lost generation (VoLG) ($/MWh) (52(5)).

181.5 The regions and customer types affected are the transmission customers whose supply would be materially interrupted following the system event, as determined by Transpower (52(4)).

182. All loads will have the same VoLL (52(7)(b)) equal to the value used in the investment test (for BBIs for which the investment test also applies), or the value in the assumptions book (see definition of VoLL in the proposed TPM). Similarly, all generators will have the same VoLG (52(7)(c)).

11.2 Rationale – demand limits

183. Demand or transfer limits with and without investment are a key input to quantifying the reliability benefits. They represent the state above which the system is at risk of losing load following a fault in the power system or a failure of a power system element.

184. We did not receive many comments on this aspect by submitters to our options consultation.

185. Vector is *" concerned Transpower's characterisation for reliability interventions which is limited to circumstances where reliability investments are targeted to relieve loading on the system. However, there will be a significant portion of Transpower's investment programme and maintenance approach that is dedicated to ensuring the condition of assets remain appropriate*." [sic]…

186. We acknowledge the demand limits shown in the above diagram may give this impression. However, our approach to determining benefits and beneficiaries for replacement and refurbishment expenditure through the standard method is influenced by the choice of counterfactual. The counterfactual to replacement of an asset due to condition should be the decommissioning of the asset (without replacement). We will then calculate demand limits if we were to remove the asset being replaced or refurbished, which will in turn reveal the benefits and beneficiaries of the asset remaining in-service.

11.3 Rationale – one VoLL for all load customers

187. MEUG and NZ Steel disagreed with using a single VoLL for all load customers. For example, MEUG submitted "*The value of reliability benefits for individual BBI will need to recognise the different reliability values for different customer types in different curtailment situations and should not be based on a single or small number of generalised VoLL estimates*". Similarly, NZ Steel submitted: "*A standard VoLL number is not an appropriate measure for direct connect customers*".

188. We acknowledge that different customer types have different VoLLs. However, the absence of any market for unplanned interruptions means that VoLL can only be quantified using the contingent valuation method (involving surveys). Although this method has widespread use in economics it is challenging to create survey questions which remove the possibility of responses that are strategic, protest-related, or biased in some way. If we use such methods to set charges on the interconnected grid, individual customers may be motivated to misstate their VoLL for the purpose of reducing their transmission charges (i.e. the free-riding problem). Therefore, we are proposing a single VoLL to be used for all load customers.[53]

189. Customers will still have the opportunity to submit on the appropriate VoLL to be used for all load customers during the investment decision making process or though the assumptions book (see Section 17 for discussion on consultation).

[53] For clarity, we note that different VoLLs remain relevant for assessing the reliability benefits of connection assets (outside the TPM), which tend to affect a single connected party.

12 Price-quantity standard method step 1: Other benefits

190. This section describes our proposal for identifying regional beneficiaries and quantifying other benefits.

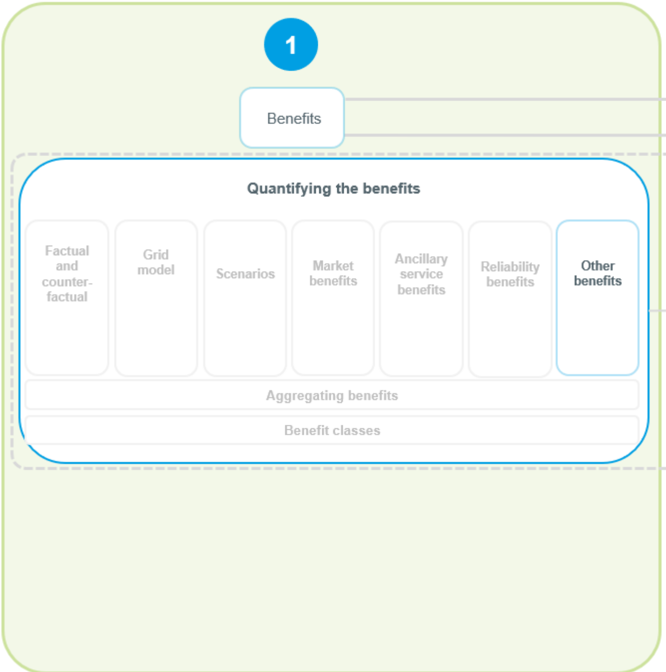


Figure 16 Price – Quantity standard method step 1 Other benefits

12.1 Our proposal

191. Under the proposed TPM, an 'other' benefit is a net-private benefit that is not market regional NPB, ancillary service regional NPB or reliability regional NPB (see definition of other regional NPB in the proposed TPM).

192. We are not proposing a methodology to quantify these benefits or identify beneficiaries within the TPM. If an 'other' benefit is used under the TPM, it would need to meet the following conditions:

- Its value can be quantified to a reasonable level of certainty without Transpower incurring disproportionate cost (53(2)(c))
- The beneficiaries are at least one of Transpower's customers, or a majority of the consumers served by at least one of Transpower's customers (53(2)(a))
- The other benefits are a material proportion of the total private benefits of the BBI (53(2)(b)).
- Other benefits can only be introduced at the time the investment is committed, not as an adjustment (53(4)).

12.2 Rationale – new benefits

193. It is possible there could be new benefits in the future which we need to consider in our investment decision making permissible under the Capex IM. For example:

- changes to wholesale market design could create new markets that are affected by transmission investment (e.g. capacity or flexibility markets)
- new technology could create new problems that can be solved by transmission investment (e.g. power quality problems caused by distributed generation)
- the Capex IM could be updated to include other types of benefits.

194. The BBC needs to be flexible enough to include new benefits such as these if they arise in the future, where they are quantifiable and are private benefits.

195. In submissions in response to our options consultation, Contact and Mercury agreed the TPM should have the flexibility to allocate unforeseen benefits if they are used in a future investment decision. Meridian disagreed *"Unforeseeable benefits like changes to market design need not be factored into the TPM now as Transpower can always amend the TPM in future if significant new benefit classes are identified."* Given the industry resources required to amend the TPM, we think it would be more efficient and practical to include unforeseen benefits where they significantly influence an investment decision (and only if consulted on with industry).

12.3 Rationale – environmental and visual amenity benefits

196. When describing clause 23 of the Guidelines in the 2019 Issues Paper, the Authority explained the purpose of this clause is to allow Transpower to include wider benefits such as environmental or visual amenity benefits "*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*."[54]

197. In a submission to our options consultation, NZIER for MEUG disagreed with using other benefits unless they are consistent with the investment test: *"To preserve consistency with the GIT the inclusion of environmental and technology benefits should be on the same basis as the Commerce Commission GIT"*. We note that paragraph B.111 of the 2019 Issues Paper explains the intent of clause 23 of the Guidelines is to allow Transpower the discretion to allocate benefits outside of the electricity market benefits assessed through the investment test e.g. visual amenity.

198. Vector[55] "*strongly encourage Transpower to quantify how much of their investment was the result of delivering "the other benefit". … it is important for Transpower to quantify how much of an impact these benefits have to the overall project*". "*However, in the example provided by Meridian and Transpower an amenity benefit – this is most likely to apply to a class of persons who are not transmission customers. …Ascribing this benefit to another grid user would be a distortion of the net private benefit of a transmission project for the grid user. … Instead, the most transparent and fairest approach would be to recover the value of these benefits through the residual charge*."

199. Meridian[56] disagreed with Vector's view: "*In terms of "other" benefits, Meridian agrees that environmental and visual amenity benefits (such as those associated with undergrounding) should be quantified and allocated to the direct beneficiaries. On*

---

54 Document reference #1 [2019 Issues paper](), paragraph B.111.
55 Refer submission and cross-submission [TPM Options consultation]()
56 Refer cross-submission [TPM Options consultation]()

Transpower's current proposal it seems there is a risk that these benefits will be aggregated into a bucket and be allocated to a wider group of transmission customers."

200. We intend to quantify benefits of BBIs to the extent reasonably practicable. The approach we are proposing recognises, consistent with the approach taken under the investment test, that not all benefits are quantifiable. We will take into account quantified benefits through the BBC and expect to only quantify other benefits rarely.

12.4 Rationale – conditions

201. To limit our discretion and give customers more certainty of when other benefits would be quantified, we have included in our proposal a number of conditions (clause 53(2) of the proposed TPM) that an 'other' benefit would need to meet to be used under the TPM. These conditions have been included to prevent speculative lobbying for other benefits, and to ensure an 'other' benefit is not allocated to a transmission customer where only a small number of a consumers served by a transmission customer are receiving the benefit.

13 Price-quantity standard method step 2: Translating the benefits to a proportion

202. This section describes our proposal for the processes to take the annual benefits for each regional load and generation group calculated in step 1 (quantifying the benefits) and process these into a single allocation percentage for each regional customer group.

203. This is the second of three steps of the price-quantity method.

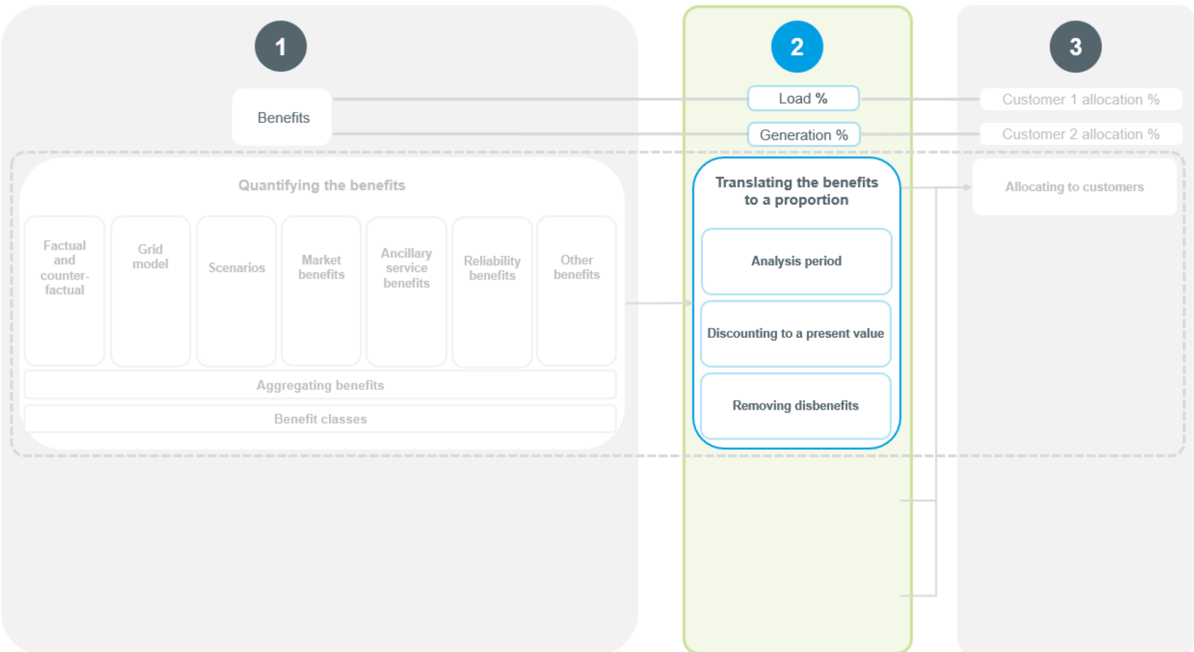


Figure 17 Price – Quantity standard method step 2 Creating proportional benefits

204. This section presents the sub-steps required to produce allocations for each regional load and generation group:

- Section 13.1: Analysis period
- Section 13.2: Discounting future benefits to a present value
- Section 13.3: Removing disbenefits.

205. Following these steps, each regional load and generation group will have a single value representing the total positive net private benefits accruing to that group. This can then be converted to a percentage representing the proportion of the total positive net private benefits accruing to all regional load and generation groups.

13.1 Analysis period

206. This section describes our proposal on the analysis period under which to assess benefits.

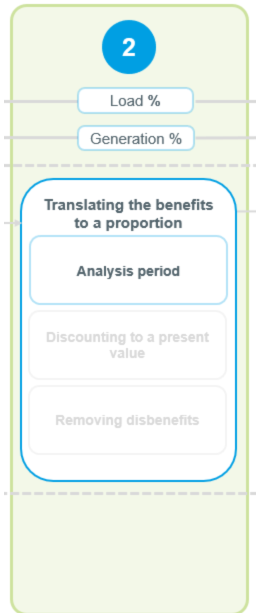


Figure 18 Price – Quantity standard method step 2 Analysis period

Our proposal

207. Benefits will be assessed over the remaining useful life of the BBI, or a 20 year analysis period – whichever is shortest (see the definition of standard method calculation period in the proposed TPM).

Rationale

208. The Guidelines require the BBC to be allocated based broadly in proportion to private benefits received over the BBIs remaining life. Transmission assets have long lives. For example, the standard physical life of transmission lines used to calculate depreciation is 55 years. However, we are proposing to depart from this requirement under clause 2 of the Guidelines because of practical considerations highlighted in clause 1(b) of the Guidelines, in particular:

- A period longer than 20 years would risk private benefits becoming increasingly uncertain[57], which may affect the robustness and simplicity of the TPM if we were to use them
- Estimating private benefits over 55 years would increase the cost of complying with the TPM as MBIE's EDGS do not extend out this long into the future; therefore, either Transpower or MBIE would have to perform these forecasts. A 20-year period is consistent with the standard analysis period used in the investment test and the typical forecasting period of the EDGS (e.g. the 2019 EDGS forecasts extended to 2050), which aids in minimizing the incremental effort on Transpower/MBIE in developing scenarios.

209. See Section 19.2 for our assessment against the Authority's statutory objective.

13.2 Discounting future benefits to a present value

210. This section describes our proposal for the appropriate rate for discounting future benefits under the BBC.

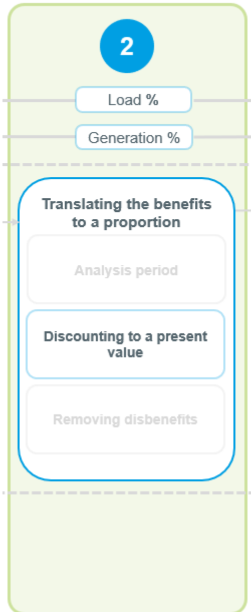


Figure 19 Price – Quantity standard method step 2 Discounting to present value

Our proposal

211. If the BBI is a tested investment, we propose to use the same discount rate as used in the application of the investment test. Otherwise, we propose to use the discount rate specified in the assumptions book or the rate specified in clause D6(3)(a) of the Transpower Capex IM (see definition of discount rate in the proposed TPM).

57 We consider private benefits to be less certain than the efficiency benefits assessed through the investment test.

Rationale

212. Transmission benefits change over the life of the asset, because usage tends to increase over time as load grows and as customers enter and exit the market – and these change transmission flows throughout the grid.

213. The Guidelines intend for allocations to be fixed over time, except in specific situations provided for by the Adjustment provisions.[58]

214. Therefore, given benefits change over time but the allocation to customers does not,[59] the annual benefits need to be discounted to a present value in order for each regional load and generation group to have a single value for the benefits we expect them to receive over the life of the asset.

215. There are several potential influences on an ideal discount rate, including:
    - Alignment with the investment decision: it would make sense for the discount rate used in calculating benefits for the investment test[60] were aligned with the discount rate used in determining allocations
    - Alignment with customers' cost of capital: benefits are received by customers and consumers (not Transpower), therefore, the discount rate could align with their cost of capital or preferences for the time value of their money
    - The level of uncertainty of benefits at a customer level: private benefits to an individual customer may be more volatile (uncertain) than aggregate benefits at a national level, which would favour use of a higher discount rate to account for this risk.

216. Of these options, we consider the use of a single discount rate the same as used in making the investment decision is preferable because:
    - it is consistent with the investment decision and the investment test
    - Clause 23 of the Guidelines states "*the treatment of benefits and costs used to calculate* ***net private benefits*** *… must be aligned with the treatment of the relevant* ***electricity market benefit or cost elements*** *under the* ***Transpower Capex IM*** *investment test*". We think the term "treatment" applies to the rate used to discount private benefits.

217. There was general support for using the same discount rate in the BBC as used in the investment test in submissions to our options consultation.

13.3 Removing disbenefits

218. This section describes the rules for removing any disbenefits identified under the standard method.

---

58 Reference document #4 Guidelines, clause 24.
59 As per the intent of the Guidelines (except where Adjustments apply which is discussed in Part C of this consultation).
60 Reference document #71 Transpower Capex IM, Schedule D6(3).

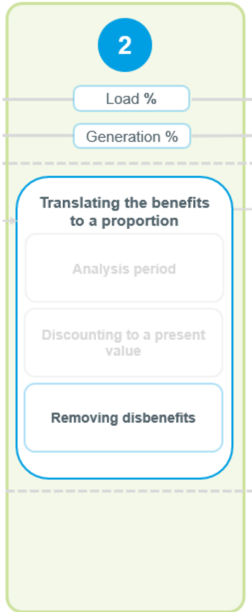


Figure 20 Price – Quantity standard method step 2 Removing disbenefits

Our proposal

219. Negative benefits are removed only after summing them with positive benefits across scenarios or time (50A(5), 50B(4)(a), and 50B(5)(a))

220. Positive and negative benefits received by the same customer in different regions are not combined (50A(7) and 50B(9))

221. Positive and negative benefits will be combined for load customers with grid connected generation at the same connection location (47)

Rationale

222. The Guidelines specify charges will be based on positive net benefits. Some transmission upgrades result in disbenefits to some parties in the grid. For example, an upgrade that removes transmission constraints will decreases prices downstream of the constraint – benefitting load customers – but resulting in a disbenefit for generation customers in this region.

223. Furthermore, some transmission upgrades may result in the same region having both benefits and disbenefits in different future scenarios. For example, South Island load consumers generally disbenefit from the HVDC in wet hydrological inflow scenarios, but benefit in dry hydrological scenarios when HVDC flow reverses direction.

224. We propose to remove negative benefits only after summing them with positive benefits across scenarios and time as it ensures the cost allocation is more consistent with the definition of an expected benefit i.e. a benefit that considers the potential for both positive and negative benefits.

225. Furthermore, we don't think we should aggregate a customer's benefits and disbenefits across regions, as this would affect competition in the electricity market by benefitting larger, geographically diverse customers for which disbenefits at some nodes would be offset by positive benefits at others (counter to the competition arm

of the Authority's statutory objective). Smaller customers would not have this opportunity. Furthermore, it would create an incentive for customers to merge with each other[61] so that positive beneficiaries can offset their transmission charges by merging with a negative beneficiary in a different region. While merging is not a problem in and of itself, we consider a transmission pricing scheme should only create incentives to merge if this is associated with more efficient transmission use, which is not the case if we were to aggregated benefits across regions.

226. There was general support for our approach to removing disbenefits in submissions to our options consultation.

227. However, Network Waitaki thought "*any removal of such "disbenefits" appears to be unfair: general reciprocity would suggest if a load or generator pay a price for receiving a benefit, they should be entitled to a discount if they receive a "disbenefit"*". Similarly, Counties Power "*questions if ignoring the disbenefits will have a perverse economic impact? For example, is there a risk that through ignoring disbenefits a new generator is subject to benefits-based charging despite the generator having greater disbenefits that would have translated to delayed future transmission investments?*" We note the Guidelines do not provide for reimbursement for a private disbenefit.

228. Similarly, Vector said: "*we recommend Transpower applies a high premium to removing disbenefits given the nature of the inter-connected grid will mean such customers will have periods where they are benefiting from the grid connection*". Our proposal is to take into account that customers will have periods where they are benefiting and disbenefiting from a BBI. Disbenefits will offset positive benefits so customers who we expect to receive net disbenefits will not receive charges for that investment. This approach accords with the concerns Vector (and others) raised in submissions on the 2019 Issues Paper[62] e.g. Vector submitted that "*the Issues Paper states that Vector received disbenefits from the North Island Grid Upgrade (NIGU) over four years, but nevertheless allocates beneficiary charges to Vector for this asset on the basis of a two-year period*".

229. NZIER for MEUG: "*These [The Guidelines'] definitions preclude the netting of benefits and disbenefits for customers as the disbenefits are valued at zero*." We disagree. The definition of net private benefit and positive net private benefit in the Guidelines guide the netting of disbenefits for individual customers. Net private benefit means "the value of the private benefits … less … the value of the private costs" for each individual designated transmission customer. If this is negative, then under the positive net private benefit definition the value is treated as zero. Consistent with our view, Orion submitted "*… negative benefits should only be removed after summing them with positive benefits over time …*".

230. Since the consultation, we have introduced an additional rule: that load customers who have grid connected generation at the same connection location as their load should have their benefits offset by their disbenefits. This was introduced because it is a legitimate – and potentially economically efficient – strategy for load customers to

[61] Subject to the cross-holding restrictions in Part 3 of the Electricity Industry Act 2010.
[62] Refer Authority website Submissions to 2019 issues paper

embed generation to reduce their transmission charges for future BBIs that have not yet been undertaken.

231. Charges would be reduced because we are proposing to use an offtake/net load metric as the metric for individual customer allocations (see Section 14). We have added this rule in order to avoid creating a potentially distortionary incentive to embed generation rather than connect it to the grid. Note, in our 2B submission[63] we proposed this rule would apply for generation and load in the same region, rather than at the same connection location. We have changed to the same connection location so as not to encourage load customers from notionally paying for the transmission charges for a generator for the sole purpose of taking advantage of this rule.

14 Price-quantity standard method step 3: Allocating to customers

232. This section identifies and considers potential intra-regional allocators, which would work alongside a regional BBC methodology adopted as part of the new TPM. This is the last of three steps in the standard method of the BBC process. It is also used for the resiliency standard method and simple methods.

Figure 21 Price – Quantity standard method step 3 Allocating to customers

14.1 Our proposal

233. For market and reliability BBIs, we propose to use the following allocators to allocate regional benefits to individual customers (63(1), and the definition of CMP B):

63 Reference document #60 Checkpoint 2B resubmission: BBC Allocation

Table 4 Allocators of regional benefit for market and reliability BBIs

Load		**Generation**
Peak demand driven investments	**Non-peak demand driven investments**	
Mean historical coincident peak offtake in the 5 year period preceding the investment	Annual mean historical offtake in the 5 year period preceding the investment	Annual mean historical injection in the 5 year period preceding the investment

234. Ancillary service BBIs use the following allocators to allocate regional benefits to individual customers (63(2)):

Table 5 Intra-regional allocators of regional benefits of ancillary services

Specified ancillary service	**Intra-regional allocator**
instantaneous reserve	mean historical **injection**
frequency keeping	mean historical **offtake**
voltage support	mean peak kVAr

235. Resiliency BBIs will use the mean historical offtake allocator (63(3)).

236. The allocator will be fixed after it is determined (unless one of the adjustment provisions apply).

237. By basing allocations on historical meter data, we will only allocate any charges to existing generation stations, direct connects, and GXPs. New customers will receive allocations when they connect in accordance with the adjustment provisions for new customers.

14.2 Rationale – fixed allocations

238. Clause 24 of the Guidelines states that a customer's share of a BBC "*will not change, save where these Guidelines permit otherwise*." Our proposals for the Adjustments provisions, through which the Guidelines permitted changes to BBC allocations in certain circumstances are explained in Chapters 10 (Adjustments) and 11 (Reassignment).

239. We note this is in contrast to the residual charge allocation which, under clause 30 of the Guidelines, is adjusted annually based on lagged changes in average gross annual energy usage. The Authority explained its decision to adopt slow-moving and unavoidable fixed-like allocators for the residual charge reflected two opposing issues:[64]

> (a)regular updating of the allocation of the residual charge based on changes to [anytime maximum demand (AMD)] risks creating relatively strong incentives for a customer to inefficiently change its grid use (perhaps by investing in alternatives) in order to reduce its allocation of the residual charge at the next update. ….

[64] Document reference #2 TPM 2019 Issues paper: supplementary consultation, paragraph 5.9.

(b) if the allocation is not updated regularly, customer charges could become increasingly misaligned with customers' size and ability to pay. ...

240. We recognise there is the potential for similar issues in relation to BBC allocations. However, nothing we have found in the 2020 Decision indicates the Authority's intent supports using an allocator than is not fixed for the BBC, even if it is slow-moving and unavoidable. In our view, using any form of dynamic allocators for BBCs would not be consistent with the intent, meaning clause 2 of the Guidelines cannot be used to depart from clause 24.

241. Most submitters to our options consultation did not comment on our view that the Guidelines require the allocator to be fixed. However, CEC for Trustpower submitted that BBCs be set on a per MW (or some other unit) tariff basis: "*The conventional approach to transmission pricing is to set a tariff, applied to a usage metric that is defined for each customer category: such as coincidental peak demand for load customers, or rated capacity for generation customers. In principle, this structure could be used for setting BBCs. Such a variable approach is examined here and compared with the TP proposal*".

242. Although CEC makes the point that the unders and overs of this approach would probably cancel out over all BBIs, there may be many BBIs where covered cost is under-recovered from beneficiaries, at least for the first several years after commissioning, and recovered from load customers (many of them geographically distant) instead. This would not be consistent with the Guidelines' requirement that the BBC recovers the covered cost of each BBI regardless of whether aggregate net private benefits exceed covered costs. Furthermore, the Guidelines (clause iv) and the Final Decision (paragraphs 9.82-9.95) are clear that the allocations are intended to be fixed at the time the investment is made (aside for adjustments and reassignment). A tariff methodology would not be consistent with the Guidelines or the Authority's intent.

14.3 Rationale – offtake and injection

243. Most submitters to our options consultation[65] did not state a preference for offtake/injection metrics (i.e. net) over gross metrics. Contact thought allocations to individual load customers should be made using gross historical and forecast coincident peak demand for peak investments, and historical and forecast gross energy demand for non-peak investments. However, the IEGA "*strongly disagree with any suggestions by generators that load be allocated BBI costs on a gross basis while generation is allocated on an average basis. ... The allocation to load (using gross load) will always exceed the allocation to generation (using average injection) even though the generator and load benefit from the same volume of electricity*."

244. We agree offtake and injection (i.e. demand/generation net of embedded generation/load) should be used because these metrics will typically correlate better with benefits than a gross load measure. For example, a load customer will receive less

[65] Refer TPM Development: Options consultation process

market benefits from the grid if their gross load is offset by embedded generation – which we should reflect in the allocator.

14.4 Rationale – historical allocation metric

245. There was general support from stakeholders in submissions to our options consultation for the use of either a historic or forecast allocator.

246. We are proposing allocations based on customers injection and offtake leading up to an investment because:

- for peak driven investments, it will provide an incentive for load customers to manage their demand in the years leading up to a potential peak-driven investment, which may result in the investment being efficiently deferred (if the cost of load management is less than the expected charge to the customer), which is consistent with the efficiency arm of the Authority's statutory objective. See also the discussion in Section 14.6 below
- for peak driven investments, a peak-based allocator best represents EPNPB
- a forecast metric may create an incentive for customers to understate their load forecast in the hope of receiving lower transmission charges at the expense of other customers (i.e. the free-riding problem). Furthermore, this would have the potential to adversely impact grid planning and the reliability of the power system, which would be counter to the reliability arm of the Authority's statutory objective
- we are already intending to use forecasts to determine regional beneficiaries. We consider forecasts to be statistically more predictable at an aggregate level because positive and negative errors for individual customers are more likely to cancel out.

14.5 Rationale – different load allocators for peak and non-peak driven investments

247. Transmission investments have several different drivers, and therefore the relationship between load customers' use of, and the benefits they derive from, an investment will be different depending on the investment. For example, the benefits from an investment that releases baseload generation are likely to occur throughout the day and year, and so best correlate with annual mean offtake, whereas the benefits of an investment that mitigates reliability risks are likely to occur at peak periods.

248. We have not used different allocators for generation because the generation groups (described in Section 5.2) are intended to combine generation stations into groups that receive benefits at similar times of the day and year. Therefore, the allocator just needs to allocate the benefit of the generation group in proportion to each generator's physical size.

14.6 Rationale – 5 year period

249. Paragraphs B.34-B.39 of the Authority's feedback on our 2B submission[66] outline a concern that the length of time used to calculate individual customer allocations may result in customers inefficiently avoiding the benefit-based charge by changing their behaviour. We have considered whether our proposed approach creates this risk and we are satisfied it does not.

250. Both the injection (for generation) and non-peak allocator (for load) are based on the mean injection/offtake measured over a five-year period (see clause 63 and the definitions of "CMP B" and "CMP F"). We consider the price signal sent by this energy metric to be too weak to materially affect operational decisions. For example, following the change from a peak-based allocation metric (HAMI) to an energy-based metric (SIMI) in 2015, South Island generators increased their maximum injection i.e. they no longer supressed their injection after the amount of time included in the metric was increased from a small number of trading periods to all trading periods.[67]

251. We consider the potential for the load customer's allocator for peak-demand driven investments to incentivise peak demand avoidance could result in more efficient transmission investment, as it could result in transmission investments being efficiently deferred. In other words, the upcoming transmission investment will be deferred if customers conclude that it would be lower cost for them to reduce their peak demand rather than accept the BBC for investment in new grid capacity.

252. We note the Authority clearly considers peak avoidance behaviour to be inefficient if it is not occurring during times of scarcity. For example,

> The current RCPD charge allocates the cost of existing transmission assets based on how much people consumed at peak in the previous year, regardless of whether there is a grid capacity constraint. It is like having a road congestion charge to discourage people from travelling in places or at times without any sign of travel delay or gridlock. The charge is recognised by many to be overly high.
>
> As a result, the RCPD charge unnecessarily suppresses electricity demand at peak times. It sends a strong signal to customers to invest in technologies such as batteries and distributed generation to avoid paying transmission charges. We have observed and been told this includes running diesel generators to avoid using the grid at potential RCPD times. These generators are expensive to run and unnecessarily increase carbon emissions.
>
> These investments and actions add costs to producing electricity and just shift transmission charges on to other consumers as overall transmission costs still need to be paid for. This ultimately increases the overall cost of consuming electricity in New Zealand. [68]

253. We do not consider the proposed allocation metric will cause such a problem because:

---

[66] Reference document #56 Letter from EA: Checkpoint 2B submission
[67] Scientia, *HAMI_SIMI Market Impact report* May 2017.
[68] Document reference #3 2020 Decision Page ii.

- the price signal will end after the investment decision has been made (i.e. so does not incentivise inefficient demand management after the investment has occurred and grid capacity has been increased)
- it would only apply to investments which are primarily driven by load customers' consumption at peak in the years preceding scarcity
- it would only apply to beneficiaries, not all customers
- unlike RCPD, the price signal would not be administratively set as a function of the cost of previous interconnection investments, rather it is an anticipated cost or "shadow price" signalling the transmission charges customers would expect to receive if they do not manage their demand leading up to the investment being commissioned.

254. We have selected the five year period based on the typical time to investigate and achieve approval through the Capex IM: the price signal needs to be sent sufficiently far in advance of the decision to commit to the investment so we can be confident our customer's response is a real trend and not a "one-off" driven by weather conditions or other exogenous drivers of peak demand. On the other hand, the shadow price signal should not be sent so far in advance that a response by customers is sent long before demand approaches the point before we need to invest, which would risk incentivising inefficient behaviour. Furthermore, the period should not be so long that it is not reflective of the recent past, which is likely to be a better proxy for future private-benefits than the more distant past. To that end, it is typically 2-7 years between the investment decision and commissioning (depending on the asset); therefore, a measurement period longer than five years would risk being too far in advance of the benefit calculation.

14.7 Rationale – ancillary service allocators

255. We have chosen the allocators for ancillary service BBIs to align with how actual ancillary services costs are allocated through Part 8 of the Code.

14.8 Rationale – resiliency allocator

256. We have proposed an average offtake allocator for this BBI class because some beneficiaries will not be causers of the investment need (as discussed in the WUNIVM case study), and therefore a peak-based allocator may result in beneficiaries managing their demand to avoid transmission charges without affecting the need for the BBI. This would have the potential to cause economic inefficiency, which would contravene clause 1(c) of the Guidelines and be counter to the efficiency arm of the Authority's statutory objective.

15 Resiliency standard method

257. This section describes our proposal for determining allocations for BBIs that are primarily undertaken to mitigate high-impact, low probability reliability risks.

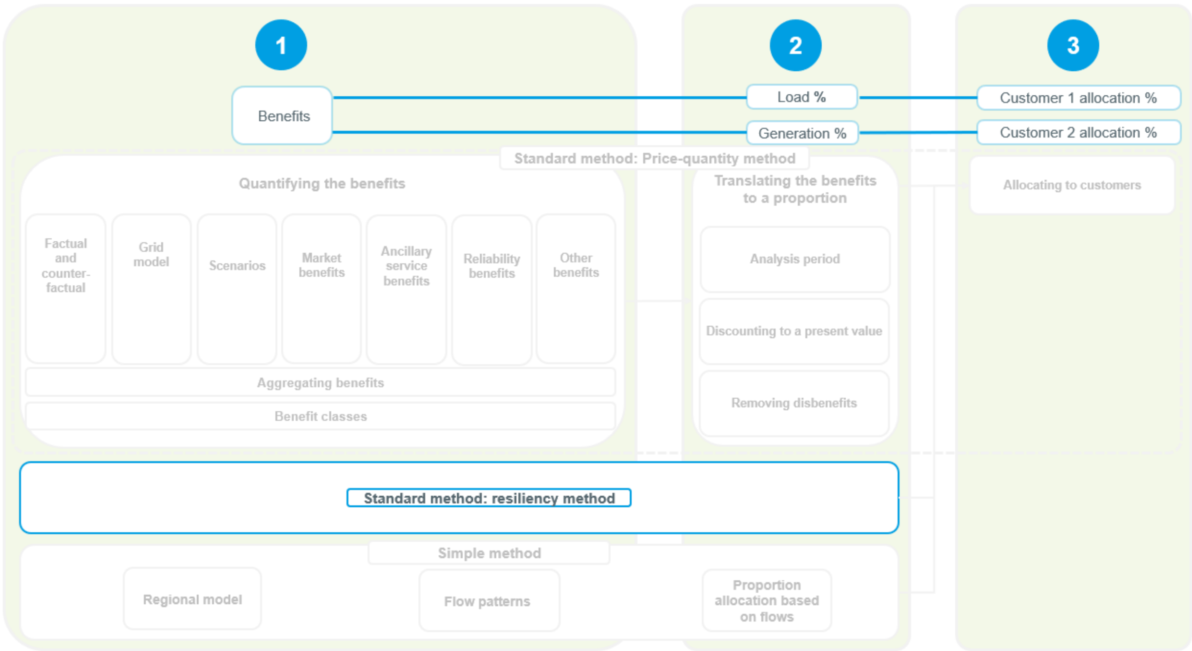


Figure 22 Resiliency standard method

15.1 Our proposal

258. We have a separate standard method (called the resiliency method) for BBIs that are primarily undertaken to avoid cascade failure or mitigate high-impact, low probability reliability risks (clauses 54-56 of the proposed TPM). For these BBIs, we propose to determine benefits and regional beneficiaries based solely on those benefits (see clause 54(1)(b) and the definitions of reliability, market, and ancillary service BBI, and other regional NPB in the proposed TPM). Therefore, if Transpower determines these benefits are not the primary driver of the investment they will not be assessed (see definition of resiliency BBI in the proposed TPM).

259. Resiliency BBIs are allocated solely to offtake (56).

15.2 Rationale

260. Conceptually, BBIs that enhance the resiliency of the power system to interruption are very similar to reliability enhancements. However, for BBIs that are primarily undertaken to mitigate uncontrolled cascade failure, we propose to use a rule-based approach to determine the regional beneficiaries of this BBI: the regional beneficiaries will be offtake customers in the island of the event being mitigated.

261. We are proposing this rule for this small class of BBIs because we do not consider it possible to determine an expected value for the benefits of the BBI (compared to a range of values), including because:

    261.1 The extent of cascade failure due to system instability is dependent on a wide range of factors including the distribution network load response, and the protection and control equipment on distribution, transmission networks and generation plant. In short, the list of plausible scenarios that could result in cascade failure, depending how multiple dynamic factors combine in real time, is almost endless.

261.2 It is possible that protection systems could successfully isolate (protect) an area of the grid if generation and load in the region are sufficiently matched to recover to an acceptable operating state. Modelling such a response would require assumptions of the many (possibly thousands) combinations of individual control and protection actions, which would be a computationally impractical.

261.3 We do not have the input information required to meaningfully model a cascade failure event. The modern New Zealand power system has never had a significant wide area voltage collapse event with which to provide an historical record to benchmark against. Even if it had, any historical data we had would be a representation of the system conditions at that specific time and not necessarily be representative of what would happen if the event occurred a second time.

261.4 The probability of a cascade failure event is difficult to determine precisely because it is so rare and because of the large number of variables affecting the probability of the event, including fault location, fault type, load, load type (motor load vs. static load), generation connected, the response of generation, and transmission outages.

262. When making investment decisions in a situation with a high degree of uncertainty, it is common to present benefits as a range of possible values rather than a single value. This is distinct from a statistical distribution because the probabilities of the range may not be known. However, if a BBI has both reliability and market benefits with different beneficiaries, we would need to determine a single value for each – we do not consider this reasonably possible for this type of BBI.

263. Similarly, for BBIs undertaken primarily to mitigate low probability resiliency risks to the power system we propose to only assess this type of benefit, again because we consider the probability and consequence of this type of event to be too uncertain to put a single value on. We are not proposing a specific rule for these investments as the regional beneficiaries are likely to be situationally specific.

264. We consider this approach consistent with clause 8 of the Guidelines, which states benefits must result in an allocation between customers "*that is broadly in proportion to their expected positive net private benefits*", which emphasises the proportionality of the benefits between customers is what matters, not the precise value. We do not consider this approach would disincentive customers from engaging with the investment decision given the Capex IM processes already in place.

265. This rules-based approach for certain types of reliability benefits is consistent with CEC's (for Trustpower) submission to our options consultation that reliability benefits from investment made under the grid reliability standards should be allocated based on simple principles.

266. We have allocated resiliency benefits solely to offtake customers rather than offtake and injection, because of the large difference between the value of lost load (~$20k/MWh) and the per MWh operating profit of generation, which is of the order of $100/MWh).

16 Simple method

267. This section describes our proposal to adopt a simple method for investments with a value less than $20m.

268. The Guidelines (Clause 20(c)) make provision for the use of one or more simple methods for the allocation of lower value (less than $20m), post-2019 BBIs.

269. Many BBIs to which the simple method would apply are low-cost (much less than $20m) investments for particular portfolios of investments. These include, using the year to June 2020 as an example, renewal and replacement throughout the country of insulator sets (874 units, total cost of $5.1m), tower attachment points (631 units, $2.9m), batteries (119 units, $2.1m) and grillage encasement works (174 units, $8.3m). The additional transaction and administration costs of using the standard method for these BBI are very unlikely to be justified.

270. The Guidelines (Clause 22) requires the simple method be capable of being implemented at lower cost to participants, including Transpower, compared to the standard method and must, in Transpower's reasonable opinion, result in an allocation of the benefit-based charge between major beneficiaries broadly in proportion to their EPNPB from the BBI.[69]

271. Clause 1b of the guidelines also requires Transpower to balance the economic benefits and costs of precision of the TPM with practical considerations such as robustness, simplicity, certainty (including limiting the need for Transpower to exercise discretion) and costs associated with developing, administering and complying with the TPM.

272. To cater for the large number and wide variety of low-value BBI applied through the simple method and satisfy the above Guideline requirements (20(c), 22 and 1(b)) we are proposing a regional allocation model with regional allocation factors for generation and load customer groups for the simple method.

273. Allocation factors to individual customers within each region is performed in step 3 using historical metered generation and load of the identified primary beneficiaries using the mean historical offtake (for offtake beneficiaries) and mean historical injection (for injection beneficiaries).

[69] We will also refer to these as primary beneficiaries. See reference document #4 Guidelines, clause 22.

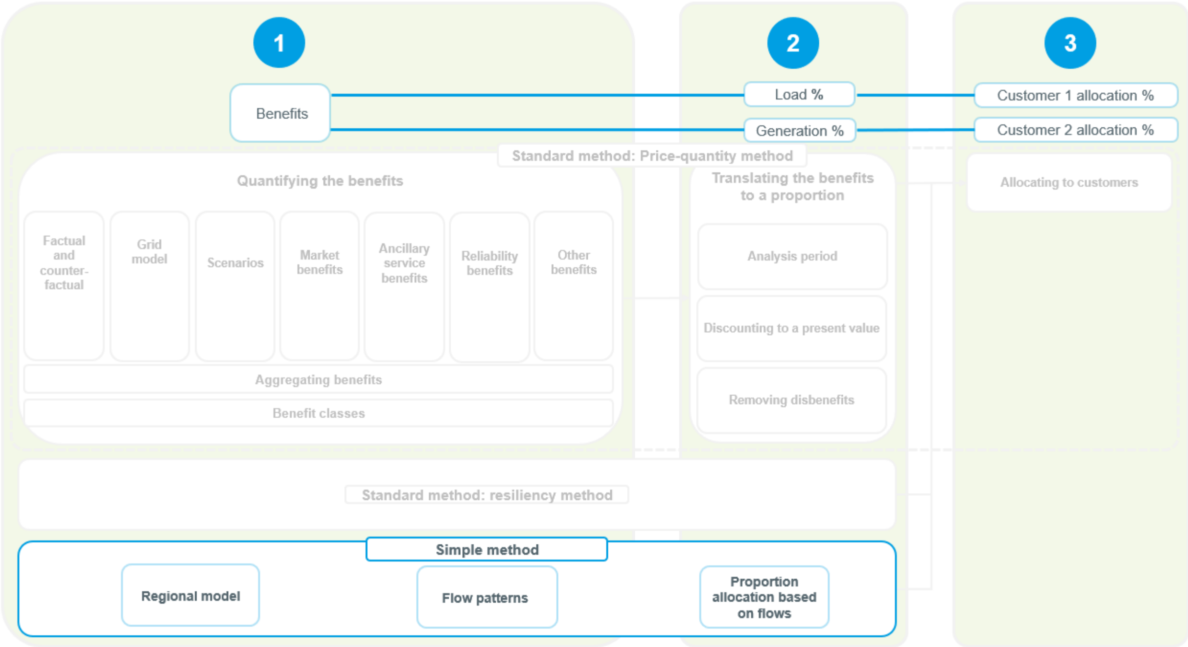


Figure 23 Simple method components

16.1 Regional definitions

Our proposal

274. We propose to use a regional allocation model for the simple method (clause 60 of the proposed TPM).

275. The regional definitions are developed using characteristics of electric power transfer and historical grid flows from the electricity market to identify regions where primary beneficiaries are more likely to be aligned. The principles for the regional definitions are:

275.1 The HVDC link is treated as a region.

275.2 There are at least two additional regions on either side of the HVDC link.

275.3 Higher voltage networks are used for bulk power transfer and would have a wider pool of beneficiaries. Prevailing directional power flow transfer patterns across AC transmission interfaces on the higher voltage grid is used to identify the largest region of power flow import on the high voltage grid.

275.4 Lower voltage networks are generally used to supply more localised regions compared to the higher voltage grid back bone and can be used to identify additional regions with more localised beneficiaries.

275.5 Separate lower voltage connection regions could be created if they connect to separate HV connection regions or they connect to the same HV connection region but is not considered a strong connection relative to the connected HV region.

276. Transpower may consider it reasonable not to assess the electricity flows over the entire HV grid.

277. Transpower may, after running the region definition process, amalgamate geographically adjacent regions of the same voltage if one region has significantly fewer market nodes than the average region.

278. The regional definitions will be included in the assumptions book.

279. The regional definitions will be reviewed every 5 years.

Rationale

280. Our current transmission system comprises 66kV, 110kV and 220kV for alternating current (AC) transmission with 350kV for high voltage direct current (HVDC) transmission. The inter-island HVDC link is unique as it connects the North and South Island AC systems and through its frequency keeping control ties the island frequencies together by modulating transfer which enables sharing of reserve and frequency keeping resources across the islands.

281. As electricity demand has grown over the decades, voltages used for transmission have increased to improve the efficiency of larger amounts of electric power transmission. Currently we use 220kV and 350kV for major bulk power transmission across the country, with some North Island circuits (Brownhill-Whakamaru) capable of transmitting at 400kV when this need arises in the future. By contrast, lower voltage transmission (less than 220kV) is generally used to supply power within more localised regions. Thus, the pool of primary beneficiaries would be more geographically dispersed for higher voltage transmission assets compared to lower voltages.

282. To define the regions for the regional allocation model, we considered these characteristics of electric power transfer on the grid and historical grid flows to identify regions where primary beneficiaries are likely to be broadly aligned. These are discussed below:

- The HVDC link is a unique asset and is considered to be a region for which we determine primary beneficiaries
- Prevailing directional power transfer across transmission interfaces on the higher voltage grid can be used to identify regions of power flow import and export across the grid. That is regions that are predominantly sending (or exporting regions) and regions that are predominantly receiving (or importing regions). These exporting and importing regions are used to help aggregate beneficiaries that are more likely to be aligned. As an example, if there are persistent power flows into the upper North Island, we would expect load customers within the upper North Island region to be more aligned with each other in terms of their benefits from accessing and using the grid than with load customers in the Lower North Island or South Island.[70] Thus, our proposed regional approach tests for these persistent flows on the high voltage grid to assist with this aggregation. We propose to use 5 years of historical half-hourly flow data from the market to

[70] Similar for generation customers. Refer submissions and cross submissions, TPM Development: Options consultation process

understand the prevailing flow patterns on the HV grid to inform the region definitions

- Lower voltage networks are generally used to supply more localised regions compared to the higher voltage grid and can be used to identify additional regions with more localised beneficiaries. However, some interconnected low-voltage regions are weakly connected relative to the HV region. As an example, the Hamilton 110kV network is electrically connected to the Wellington 110kV network but they are weakly connected on the 110kV relative to their parallel high voltage (220kV) connection. Thus, we would not expect the primary beneficiaries of investments in the Wellington low voltage network to be broadly aligned with primary beneficiaries for investments in the Hamilton low voltage network even though they are electrically connected. Thus, our proposed regional approach allows for separate low-voltage regions that are weakly connected (relative to their parallel high-voltage connection) or if adjacent low-voltage regions are connected to different high-voltage regions.

283. The majority of the submitters that responded to the regional definition for the simple method indicated a preference for larger rather than smaller regions (e.g. Contact, Network Waitaki and Orion).[71] Counties Power raised a general concern, not specifically related to the simple method, on regional aggregation and being grouped into a region with Auckland where there might be a large proportion of costs for which they do not receive benefits.

284. We also consider there are practicality benefits and lower administration costs of larger regions (as opposed to more granular regions) for the simple method. The application of the simple method will largely be to base capex spend which would be forecast at the start of each Regulatory Control Period (RCP). However, as the TPM is applied over time we expect customers to focus on the difference between forecast regional spend (which will inform the forecast of charges by region) and actual regional spend (used for the actual charges by region). All else being equal, we'd expect the forecast versus actual base capex spend would tend to have lower variances the larger the region. This could be due to a number of practical reasons such as:

284.1 re-prioritisation of projects due to service provider/external consultant availability where actual spend could reduce in one region but increase in another region. The larger the region, the lower the forecast versus actual cost spend variations.

284.2 differences between actual asset health (based on site inspections) versus forecast asset health (based on asset health prediction models). Asset condition-based forecast spend is informed by asset health prediction models. However, the actual asset health (following a site inspection) may be worse or better than

[71] In response to the number of aggregate regions for the simple method in our November 2019 BBC options consultation paper Contact's response was, "*We think using the existing four regions used under the RCPD is a way of reducing providing continuity and simplicity. This would be our preference*". Network Waitaki's response was, "*Agree with Transpower's view of either 7 or 4 regions to use under all methods*" and Orion's response was, "*…we support the use of a simple method that might help spread costs more broadly in the region of benefit for these smaller projects. As such, we support wide region definitions for all voltage projects [questions 3.3 & 3.4].*"

forecast which could result in more or less additional work than forecast. These variations would be expected to cancel out the larger the region.

284.3 building block cost models (based on historic projects) are used to inform project cost forecasting with project-specific complexity assessed closer to the start of the project. Such complexities could be space constraints, bespoke equipment etc. These variations would also be expected to cancel out the larger the region.

285. We expect greater administrative costs would be required as part of asset planning to reduce the variances between forecast and actual spend the more granular the regions if these forecasts are being used to inform expectations of future transmission charges in a region. These additional costs could be to contract additional service providers in different regions and incurring additional processes and costs in preparing the base capex forecasts (e.g. by doing additional site inspections to incorporate site complexities at the planning stage and investing additional resources to improve the regional health forecast models). Failure to do so with more granular regions would result in increased variances between forecast charges (based on forecast spend) and actual charges (based on actual spend) which would increase the uncertainty of transmission charges to customers in these regions.

286. Recognising the requirements to balance precision with practicalities and cost considerations (as required by the Clause 1(b) of the Guidelines), where beneficiaries are aligned in terms of their benefits from being connected to and using the grid, our proposed approach for the regional aggregation opts for larger as opposed to more granular regions. An example of the 20-region definition produced from our current process is provided in Section 21 of this chapter.

287. To reduce the level of discretion in developing the regional definitions, the principles and rules based on the above characteristics are provided in the TPM (see clause 60 of the proposed TPM). We propose to publish in the assumptions book the latest regional definition for use in the simple method. We also envisage the process based on these principles and rules specified in the TPM will be included in the assumptions book.[72] We consider this is a reasonable approach to:

287.1 maintain the TPM at a principles level providing the intent of the approach to define regions where primary beneficiaries are broadly aligned.

287.2 allow for refinement of the more detailed process[73] (still consistent with intent in the TPM) as we get more experience with the new TPM without needing to change the TPM. We are proposing to consult on the assumptions book subject to certain provisions as discussed in the proposed TPM (see clause 39). We would expect changes to the regional definition process that can impact the regional boundaries for the simple method to be a material change.

287.3 This does not preclude that over time as we have more experience with administering this process and the simple method, some of the more detailed process could get incorporated into the TPM if beneficial to do so.

---

72 An example of the detailed process used for the indicative pricing analysis together with an illustration of the resulting 20 aggregated regions as a result of using this process is provided in Section 21 of this chapter.

73 We anticipate this will be in the assumptions book.

288. To reduce potential boundary effects and account for changes in the grid and how this may change the alignment of primary beneficiaries in different parts of the grid, we propose the regional definitions be reviewed at least every 5 years. Any change to the regional definitions would be consistent with the TPM with the latest regional definition published in the assumptions book.

16.2 Identifying primary beneficiaries

Our proposal

289. We propose to use a regional model with regional injection, offtake and interregional import and export flows to identify primary beneficiaries in the simple method. The primary beneficiaries of a low value BBI in a region allocated through the simple method are (see clause 62(5) of the proposed TPM):

289.1 Injection and offtake customers located within that region.

289.2 Injection customers in other regions exporting power to that region.

289.3 Offtake customers in other regions importing power from that region.

Rationale

290. The interconnected grid provides benefits to generators and loads. The grid enables regions with excess generation to supply loads in other regions to the benefit of both generators in the exporting region and loads in the importing region. Loads benefit from being able to access more lower cost generation sources and generators benefit from having access to more load customers to sell the electricity they generate.

291. The majority of the low-value BBI allocated through the simple method would be to maintain the functionality of the existing grid and therefore maintain the benefits generators and loads get from continued access to the interconnected grid.

292. We therefore consider a quantity-based metric is a reasonable proxy for the benefits generators and loads receive from their continued access to the interconnected grid and therefore the benefits they continue to receive from the BBI to maintain the functionality of the grid.

293. The Authority in its feedback to our Checkpoint 2B submission was generally supportive on the use of a quantity-based, rather than a price-based approach for the simple method: "*We agree that, for practical reasons, it is appropriate for the simple method to focus on quantities and need not explicitly take price effects into account. This is because the simple method needs to be capable of allocating the costs of a large volume of (generally) routine lifecycle investments. Attempting to incorporate price effects into the large number of simple method assessments (that Transpower expects to process every year) is unlikely to be possible in a way that is both cost effective and would materially improve the precision of the allocations to beneficiaries.*"[74]

[74] Reference document #56 Letter from EA: Checkpoint 2B submission.

294. In our November 2020 options consultation paper for the BBC, we considered the use of power flow-based sensitivity factors to develop the simple method for higher voltages with lower voltages allocated solely within the region[75].

295. While there was support for this power flow-based sensitivity factor approach from Network Waitaki, other submitters questioned the complexity of that approach for the simple method, its ability to be replicated by others and the complexity of administering this approach (Contact, ENA and Mercury).

296. Following review of those submissions, we have considered our approach for the simple method taking into consideration that the Guidelines and our design principles emphasise simplicity and practicality of solutions where appropriate as well as the cost of implementation (Clause 1b and 22 of the Guidelines). We also considered the replicability of the approach. Given this, we've evolved our approach to a simpler methodology for identifying the primary beneficiaries expected to benefit from low-value BBIs using the simple method.

297. The proposed approach for the simple method uses flow direction between the defined regions to determine the primary beneficiaries of regional low-value BBI.

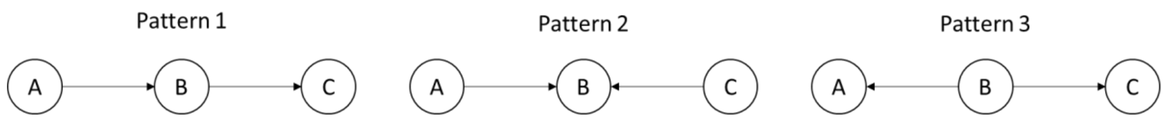
298. We consider that the primary beneficiaries of assets in a defined region (these include assets within the region and assets importing power into that region) are injection and offtake customers in that region, injection customers exporting power to that region and offtake customer importing power from that region.

299. Injection and offtake customers within a region benefit from investment in that region since the regional network provides them access to regional generation, regional loads as well as connection to the wider interconnected grid. Access to the wider interconnected grid includes access to a synchronous AC system with additional system strength, voltage support and ability to meet generation and load deficits within the region.

300. Injection customers in other regions exporting power to a region benefit from investments in the receiving region as this provides the injection customers in the sending region access to more load. Similarly, offtake customers in other regions importing power from a region benefit from investment in that region since it provides the offtake customers in the receiving region access to more generation.

301. These rules are illustrated in the following example showing the primary beneficiaries under different flow patterns for a 3-region network.

[75] These power flow-based sensitivity factors (also called power flow distribution factors) can be calculated using power flow software (such as PowerFactory) and determines how much an increase in load at a node results in an increase in loading on an asset (e.g. a circuit or transformer). Assumptions are made on which generators increase output to supply the additional load. These would be load sensitivity factors. Similar factors can be calculated for generators at different nodes.



Region	Primary beneficiary
A	Ga, La, Lb, Lc
B	Ga, Gb, Lb, Lc
C	Ga, Gb, Gc, Lc

Region	Primary beneficiary
A	Ga, La, Lb
B	Ga, Gb, Lb, Gc
C	Lb, Gc, Lc

Region	Primary beneficiary
A	Ga, La, Gb
B	La, Gb, Lb, Lc
C	Gb, Gc, Lc

Figure 24 Simple method Illustration of flow directions to identify beneficiaries

302. In the above example, under flow pattern 1, the primary beneficiaries for a low-value BBI in region B would be:

    302.1 generation and load in region B

    302.2 generation in region A (exporting power to region B)

    302.3 loads in region C (importing power from region B)

303. Many of the low-value BBI applied through the simple method would be on primary assets such as towers and lines (e.g. tower painting or insulator replacement) but others would be on secondary assets such as protection systems. These investments in secondary systems enable or preserve the capability of the primary assets to continue to function. Thus, we consider the beneficiaries of the primary asset (assessed through the flow patterns) to also benefit from the BBI on associated equipment and secondary assets on the interconnected grid. Therefore, we consider the regional allocation model with flow patterns to apply to all low-value BBI allocated through the simple method.

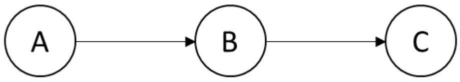
16.3 Allocation between primary beneficiaries

Our proposal

304. The allocation of a BBI within each connection region would be based on the primary beneficiary aggregate MW quantities by customer groups (i.e. injection and offtake)[76].

305. The following simplified illustration provides a description of the proposed allocation (also called simple method contribution in the proposed TPM) to primary generation and load beneficiary customer groups based on the grid flow pattern in a trading period (see clauses 62(4)-62(6) of the proposed TPM).

[76] The simple method allocations are undertaken at the customer group level with allocation to individual points of connection done in step 3.



		A	B	C
	Primary beneficiaries	Ga, La, Lb, Lc	Ga, Gb, Lb, Lc	Ga, Gb, Gc, Lc
Allocation	Ga	$\frac{G_a}{(G_a + L_a + F_{a\_b})}$	$\frac{F_{a\_b}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{F_{a\_b}}{G_b + F_{a\_b}}\right)$
	Gb	0	$\frac{G_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{G_b}{G_b + F_{a\_b}}\right)$
	Gc	0	0	$\frac{G_c}{(G_c + L_c + F_{b\_c})}$
	La	$\frac{L_a}{(G_a + L_a + F_{a\_b})}$	0	0
	Lb	$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{L_b}{L_b + F_{b\_c}}\right)$	$\frac{L_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	0
	Lc	$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{F_{b\_c}}{L_b + F_{b\_c}}\right)$	$\frac{F_{b\_c}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{L_c}{(G_c + L_c + F_{b\_c})}$

Figure 25 Illustration of regional allocations under the Simple method (the simple method contribution SMC)

306. Based on the grid flow patterns, beneficiaries of region A BBI allocated through the simple method would be:

- Region A generation and load
- Load in region B and C (importing power from region A)

307. The proportional allocations (simple method contributions) are calculated for each trading period over a 5-year historical measurement period with the weighted-average across all trading periods used as the regional net private benefit (RNPB) for each regional customer group for the simple method (see clause 62(2) of the proposed TPM).

308. Allocation to individual customers within a region would be based on their measured injection and offtake relative to the total injection and offtake of customers in that region and customer group (see clauses 59(1), 59(2), 63(10), 63(11) of the proposed TPM).

Table 6 Simple method, intra-regional allocation to customers

Load	Generation
Annual mean historical offtake in the 5-year capacity measurement period preceding the simple method period	Annual mean historical injection in the 5-year capacity measurement period preceding the simple method period

Rationale

309. In the previous Section (16.2) we explained why we consider a quantity-based metric is a reasonable proxy[77] for the benefits generation and load customers receive from their continued access to the interconnected grid and therefore the benefits they continue to receive from the low-value BBI to maintain the functionality of the grid.

310. We consider that the greater quantities generation and load customers in a region contribute to the total MW generated, consumed and transferred into and out of a region, the greater their benefits derived from the interconnected grid.

311. We therefore consider it reasonable that using the proportion regional generation and load customer groups contribute to injection and offtake in each region is broadly proportional to the EPNPB they receive from the grid and from the low-value BBI primarily used to ensure the grid continues to deliver its functionality. These proposed simple method contributions for a simplified illustrative example is shown in paragraph 305.[78]

312. Given our hydro-dominant system, power flow patterns change on the grid, and therefore the benefits generation and load customer groups in different regions get from different parts of the interconnected grid can vary over time. As an example, with HVDC flowing south, South Island loads benefit from parts of the North Island grid and similarly during HVDC north flow conditions, North Island loads benefit from parts of the South Island grid. We consider that a using a 5-year historical period is reasonable to capture a range of power flow patterns to calculate the simple method contributions.

313. We propose to calculate the simple method contributions at the half-hourly level over 5 historical years and use a weighted-average of the half-hourly simple method contributions for each regional customer group. We propose to weight each trading period equally.

314. The simple method contributions determine the regional allocations for generation and load customer groups. The customer's proportion of the total regional customer groups injection (for an injection customer) or offtake (for an offtake customer) would be based on the annual average injection and offtake respectively over a 5-year period. This is consistent with our consideration for the simple method that customers injection and offtake from grid is a reasonable estimate of their EPNPB[79].

315. The Guidelines allow for the simple method to exempt customers who do not receive major positive net private benefit (Clause 22(c)). Our proposed approach uses the defined regions and the allocation factors as described in the above sections to determine the primary beneficiaries of BBI allocated through the simple method and allocations we reasonably consider are broadly in proportion to EPNPB. The approach

77 The Authority is supportive of this approach as discussed in paragraph 293.

78 Generation and load MW contributions using the proportional allocation approach was implemented using the proportional flow-tracing algorithm. The proportional allocations from the flow-tracing algorithm is equivalent to those in the simplified example.

79 Customer allocations using the proposed simple method are provided in Appendix B.

does not require any additional specific exemptions for customers who do not receive major positive net private benefits hence we are not proposing any.

16.4 Weighting between generation and load beneficiaries

Our proposal

316. The proposed proportional allocation under the simple method results in an aggregate allocation between generation and load that is broadly 50:50

317. Our proposed simple method includes a customer group adjustment factor that could adjust the allocation between aggregate injection and offtake customers (62(2)).

318. Our proposal is to start with a regional customer group adjustment factor of 1 for both generation and load customer groups[80].

319. We propose to review the adjustment factor at least every 5 years and updating its value based on the average aggregate generation/load splits as determined from post-2019 standard method BBCs provided there are at least 10 post-2019 standard method BBIs (62(3)).

Rationale

320. The proposed proportional allocation approach using quantities results in an allocation between aggregate generation and aggregate load that is roughly 50:50.

321. The Authority requested we assess the appropriateness of this for BBC allocation under the simple method and whether this is reflective of the net private benefits to generators and loads.

322. In its Checkpoint 2B feedback, Authority staff indicated it is appropriate to develop these generator/load weightings using simplifying assumptions for the simple method, "*We consider that it is appropriate for the simple method to include simplifying assumptions (such as a single generation/load weighting). However, it is also important that those assumptions and therefore the allocations are well justified, and broadly reflect the relative benefit generation and load customers are expected to receive from investments allocated through the simple method, in order to ensure consistency with the guidelines*".

323. We agree with the Authority that a simplified single generation/load weighting is appropriate for use with the simple method. However, our primary concern on using an assumptions-based analytical approach for this weighting is the large potential variations in this assessment with the potential for a false sense of precision depending on the choice of input assumptions into these calculations.

324. Authority staff provided Transpower with additional analysis and data for consideration on the generator/load weightings as part of their feedback on our Checkpoint 2B resubmission. In this response the Authority indicated "*The data appear to indicate that an allocation of simple method BBIs to generation in the range of 20–30% (and 70–*

80 This means a roughly 50:50 allocation between aggregate generation and load for BBC allocated via the simple method.

80% to load) may be appropriate. We request Transpower considers this data as it finalises its proposed TPM".[81]

325. To demonstrate the range of potential outcomes with these assessments, we considered the simple ratio estimate of generation and load shares approach (method 1) provided by Authority staff for our consideration. This analysis considered the ratio of generator benefits to generator plus purchaser benefits using wholesale market payments by purchasers (in aggregate) as a proxy for total purchaser benefits and operating profit and net profit after tax as proxies for generator benefit. This analysis considered the generators as gentailers,[82] thus including the cost to serve their contracted load as an operational cost[83]. No commensurate adjustments were made to the loads with the purchaser benefit proxy still assumed to be the total load purchases on the wholesale market. These assumptions would tend to reduce the generator benefits relative to the purchaser benefits. Using this approach, the calculated proportion of aggregate generator benefits to total benefits[84] was 20-28% (with 72-80% being the aggregate benefit to loads).

326. We undertook a high-level sensitivity analysis on that assessment and sought to estimate the same ratios but estimating only operational profits (spot revenue less operational costs) related to generation only. We call this measure the adjusted operating profit shown in the table below. This was estimated from the 5 large gentailer financial statements considering their New Zealand spot generation revenue and estimated costs[85] related to operating their New Zealand generation. Using this adjusted operating profit as a proxy for the benefit of generation only and calculating the ratio to total (generation plus purchaser) benefit, the proportion of the benefit calculated for generation only increases from 20-28% to 40-50%. This represents a 78-100% increase in generation benefits.

Table 7 Adjusted operating profit of 5 large gentailers

		2020	2019	2018	2017	2016
Generation share	*%*	89.67%	89.98%	90.56%	90.45%	90.31%
Whole sale revenue	*$m*	4251	5478	3568	2292	2482
Adjusted Operating profit	*$m*	**2585**	**3699**	**2946**	**2009**	**2180**
Estimated industry value based on Adjusted Operating profit	*$m*	2883	4111	3253	2256	2413
Implied generator weighting	*%*	***40%***	***43%***	***48%***	***50%***	***49%***

327. The large potential variation in these benefits is also observable from the schedule 1 allocations calculated by the Authority and provided in the Guidelines. The table below shows the percentage allocation between aggregate generation and load

81 Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A-D, Appendix B
82 The Authority analysis noted this assumption introduced errors into its calculation.
83 These costs also included fixed generator costs such as depreciation.
84 Total benefits being aggregate generator plus aggregate load benefits.
85 These costs included components such as fuel-related, operating and transmission costs.

customers for each of the pre-2019 BBIs. Here we see the range of outcomes for different BBI from ~100% to loads for the LSI Renewables project to roughly equal allocations between generation and load for the Wairakei Ring and HVDC link pre-2019 BBIs.

Table 8 Allocations to Load and Generation for Schedule 1 BBIs

Pre-2019 BBI	Load	Gen
Bunnythorpe-Haywards	95.0%	5.0%
HVDC	49.6%	50.4%
LSI Reliability	74.7%	25.3%
LSI Renewables	99.7%	0.3%
NIGUP	73.8%	26.2%
Wairakei Ring	46.1%	53.9%
UNI Dynamic Reactive	73.8%	26.2%

328. As part of the Authority's response[86] to our checkpoint 2B resubmission it included a summary of an updated survey on the proportion of (we assume) interconnection (shared) transmission charges allocated to generators versus loads from international jurisdictions which was provided as part of Meridian's submission to the 2019 Issues paper[87]. This assessment shows most surveyed jurisdictions have larger allocations to loads compared to generators[88].

329. While we acknowledge each jurisdiction is different in terms of its market and regulatory structure, transmission system and transmission charging regime, in order to produce a like-with-like comparison to New Zealand, we would need to reflect that 100% of the residual charge will be allocated to load. Accounting for the residual charge, we estimate that generators (in aggregate[89]) would be allocated ~15% of the non-connection transmission charges for the 2020/21 pricing year (our indicative pricing for the new TPM). This could potentially change to ~12-37% in the 2034/35 pricing year. The 2034/35 estimate is based on expenditure forecasts and a number of simplifying assumptions, one of the salient ones being allocations between generation and load for BBC allocated via the standard[90] method. For this 2034/35 high-level estimate we have assumed a range of allocations representing the average allocation between load and generation under the standard method (from 50:50 to 90:10). In line with the proposed approach for the single allocation between load and generation for

86 Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A-D, Appendix B, xxxiii.
87 Meridian Energy TPM submission 1 October 2019, page 9 of NERA review.
88 In Europe, Sweden's allocation was closest to an equal split with 62% allocated to loads and 38% allocated to generators. In the "Others" sample Chile had an allocation of 20% to loads and 80% to generators with South Korea allocating the costs equally between generators and loads (50/50).
89 While this is an estimate of allocation to generators in aggregate, allocation to individual generators under the simple method would be based on the simple method regional allocation factors and customer allocation factors as discussed earlier in this section (Section 16 of this chapter).
90 Given the effort involved in developing the standard method allocations it was not possible to calculate the project specific allocations for this analysis.

the simple method, discussed in paragraph 319, we assumed the same load/generation split for the simple method[91] as that for the standard method.

330. Even with these assumptions, when comparing the total non-connection transmission cost allocation between generation and load, the split under the proposed TPM is broadly in line with those from the survey, as shown in the next figure.

331. We also note that as part of its post-2025 market development the Energy Security Board in Australia acknowledged that both generators and loads benefit from the transmission network and the difficulty in precisely assigning costs between them. In its paper it indicated the most straightforward method could be a fixed division such as 50/50.[92]

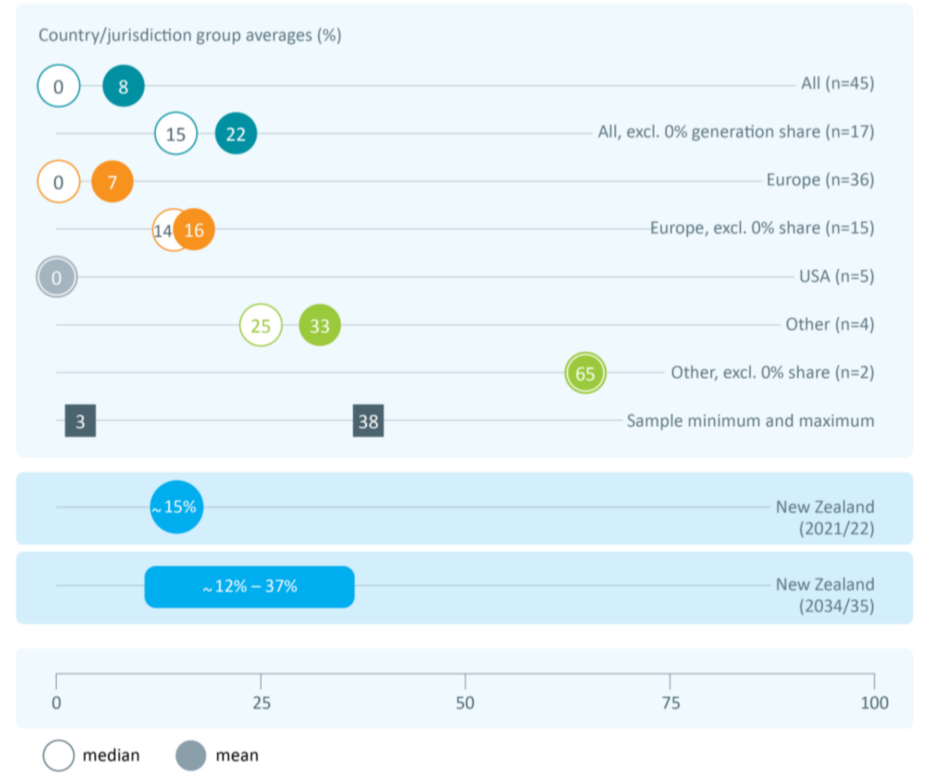


Figure 26 Comparison of transmission charges to load and generation, across grouped jurisdictions

332. Following our further analysis we consider that:

332.1 Our high-level assessments of relative benefits indicate that a roughly 50:50 split between generation and load for the simple method is within the range of estimates. Thus we consider the roughly equal generation load split provided by the proposed proportional allocation approach[93] for the simple method is a reasonable starting point.

[91] We discuss this further in this section.

[92] Energy Security Board *Post-2025 Market Design Options – A paper for consultation* April 2021, page 86.

[93] Which would be a roughly 50:50 split between aggregate generation and aggregate load.

332.2 Estimating a fixed allocation based on expected benefits to weight the simple method charges between generation and load customers can be very sensitive to the choice of input assumptions. We consider this sensitivity could undermine its robustness if used to allocate customer charges. Alternatively, if much more complicated approaches are used to develop these fixed allocation weightings, it could undermine the requirement of the Guidelines (Clause 22(a)) that the simple method must be capable of being implemented at lower-cost than the standard method.

332.3 A reasonable alternative would be to use the generation/load split of post-2019 BBI under the standard method to inform the generation/load split under the simple method. Therefore, we propose to have a 5-yearly review of the generation/load adjustment factor for the simple method and update the adjustment factors using an average of the aggregate generation/load splits from at least 10 post-2019 BBI applied through the standard method.

333. We consider the proposed approach has several advantages for developing the generation/load allocation factor. In the longer-term as more investments are applied through the standard method it would better reflect the expected benefit split between generation and load. We have considered at least 10 post-2019 BBIs applied through the standard method should be in place before we utilise this load/generation weighting. Furthermore, the allocation factors would be developed considering the changing use of the grid and changing technology and thus better capture the changing aggregate generation and load benefits from use of the grid over time. We also note that this would also be consistent with our proposal[94] where some low value refurbishment and replacement investments on post-2019 BBIs may be treated as part of the underlying BBI and therefore take on the allocations of the underlying BBI[95].

334. The guidelines for the simple method requires an allocation between primary beneficiaries broadly in proportion to expected positive net private benefits (Clause 22(b)). The guidelines also require the TPM to balance precision with practical considerations (Clause 1(b)). We consider our proposal is consistent with the guidelines.

17 Consultation on benefit-based charges

335. This section describes our proposal for consultation on BBC allocations and related input assumptions.

336. The investment approval consultation requirements under the Capex IM are relevant to the discussion in this section. The Commerce Commission regulates the way in which decisions are made to invest in the grid, including through determining, and on a regular basis reviewing, the Transpower Capex IM (**Capex IM**) and approving

94 See Chapter 10, Section 5.
95 The underlying BBI allocations being through the standard method.

Transpower's proposed capital spend. The Capex IM comprises the rules and processes for approving capital expenditure (Transpower's applications and the Commission's assessments), including the investment test that we must apply to our investments over $20 million in order to recover costs through the TPM. Once Transpower's capital expenditure proposal has been approved by the Commission, whether as major capex or base capex, that spend may be recovered through the TPM. As the Commission stated in its recent approval of our Bombay Otahuhu Regional major capex project (**MCP**):[96]

> The new TPM guidelines and the new TPM Transpower develops under them will not affect the regulatory approval process for assessing the MCP under the Capex IM or the amount Transpower can recover in transmission charges for the investment.

337. Under the Capex IM, we are required to consult on individual investments in two situations:[97]

 337.1 Major capex projects: These are enhancement and development (E&D) projects expected to cost more than the base capex threshold ($20m). Allowances for major capex projects are not set by the Commission at the start of a regulatory control period.

 337.2 High-value base capex projects: These are asset replacement or refurbishment (R&R) projects that are expected to cost more than the base capex threshold. These projects may be funded from our base capex allowance set by the Commission at the start of the regulatory control period or, for certain "listed projects", there may be an increment to our base capex allowance.

338. Under the Capex IM, the Commission is also required to consult on our major capex and listed project proposals.[98]

339. The Guidelines are aligned with these requirements because they require consultation on BBC allocations for high-value BBIs only, being those BBIs with a capital spend greater than the base capex threshold under the Capex IM.

340. These consultations include consultation on the assumptions underlying the investment need, including Transpower's load growth assumptions.[99] Clause 23 of the Guidelines requires the BBC allocation to be consistent with those assumptions and with the treatment of costs and benefits generally under the investment test (clause 43(3) of the proposed TPM).

17.1 Our proposal

341. As required by clause 5(b) and (f) of the Guidelines, Transpower will consult publicly on:

 341.1 the expected total covered cost of each high-value post-2019 BBI;

 341.2 the initial allocation of the BBC for each high-value BBI; and

---

96 Commerce Commission *Decision and reasons on Transpower's Bombay Otahuhu Regional MCP* 19 March 2021, paragraph 27.

97 Reference document #17 Transpower Capex IM, clauses 8.1.2 and 8.1.3.

98 Transpower Capex IM, clause 8.1.1.

99 We agree with Vector's submission that it is important Transpower's load growth assumptions continue to be tested through the investment approval consultation processes.

341.3 any material changes to the expected total covered cost or BBC allocation for each high-value post-2019 BBI,

before the BBC or adjustment is finalised (clause 17(1) of the proposed TPM). Consultation under the proposed TPM is discussed further in Chapter 3 (Preliminary).

342. The consultation may be carried out as part of Transpower's investment approval consultation under the Capex IM (clause 17(3) of the proposed TPM).

17.2 Rationale – consultation process for high-value post-2019 BBIs

343. The diagram below shows the main process steps for major capex proposals.[100] The top half shows the steps that are required under the Capex IM, and the bottom half indicates how we consider covered cost and BBC allocation consultation for high-value post-2019 BBIs could align with these steps.

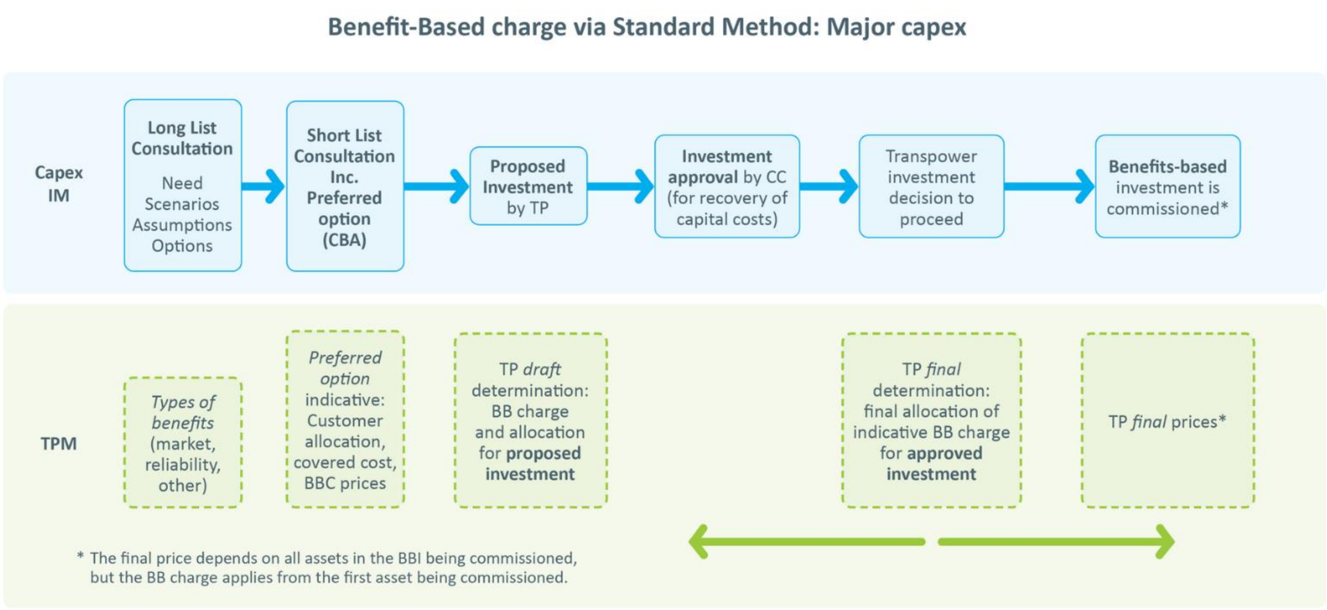


Figure 27 Consultation steps for Major Capex Projects, and BBC covered cost and allocations under the TPM

344. We expect to align the timing of the final BBC allocation determination with the time of Transpower's final investment decision rather than the time of the investment proposal (which was our initial thinking) because:

344.1 the Commission's investment proposal evaluation can take several months, during which time electricity market conditions may change; and

344.2 Commission approval does not necessarily mean Transpower will undertake the investment immediately, and again, electricity market conditions may change in the interim. For example, the CUWLP project was originally approved by the Electricity Commission in 2010, but not committed until 2020.

[100] The process steps for high-value base capex projects, including listed project proposals, are different. For high-value base capex projects, we would align our BBC allocation consultation in broadly the same way as shown in the diagram.

345. Our proposal is to calculate the covered cost for a BBI annually based on the values of the commissioned assets comprised in the BBI and recorded in Transpower's asset register (see Chapter 6 (BBC Covered cost). Accordingly, the total size of the BBC, and the size of customers' individual shares of it, will not be known at the time of Transpower's investment proposal, the Commission's approval of it, or Transpower's final investment decision. We will need to estimate those values based on the expected cost of the investment and the allowances approved by the Commission (multiplied by the final BBC allocation determination). We do not propose to consult on the routine annual calculations of covered cost.

346. We anticipate our consultation approach for high-value BBIs will evolve as we, and our stakeholders, gain experience with administration of the new TPM. We expect our approach will also be influenced by our experience with consultations we undertake on other matters unrelated to transmission pricing.

347. We received support for the alignment of consultation on BBC allocations with the investment approval process in submissions on our BBC options consultation.

18 Assumptions book

18.1 Our proposal

348. We propose to have an assumptions book. The assumptions book will contain the assumptions and detailed methodologies we intend to apply for allocating and adjusting BBCs, which we do not expect vary between BBIs (clause 39(1) of the proposed TPM and proposed definition of "assumptions book").

349. At a minimum, the assumptions book will contain the modelled regions, regional NPBs, demand adjustment factor (if not 1) and simple method factors for each simple method period (clauses 59(3), 60(2), 62(1) and 62(3) of the proposed TPM).

350. Except as to those parameters, the assumptions book will not be binding on Transpower or any independent expert (clause 39(5) of the proposed TPM). The assumptions book must not contain any assumptions or methodologies that are inconsistent with the Code, including the TPM (clause 39(2) of the proposed TPM). The assumptions book is not intended to replicate, and cannot change, the fundamental and structural requirements for allocating or adjusting BBCs, which we consider are specified at an appropriate level in the TPM itself.

351. We must review the content of the assumptions book at least every seven years and consider whether anything in it is appropriate to carry into the TPM by way of operational review (clause 39(6) of the proposed TPM). This is to ensure that any assumption or methodology in the assumptions book that proves resilient over time becomes a binding requirement for BBC allocation or adjustment.

352. We will consult with customers on the assumptions book and any update to it before publication, subject to limited exceptions that mirror those that apply to the Authority's consultation on Code amendments under section 39(3) of the Electricity Industry Act 2010 (clauses 39(3) and (4) of the proposed TPM). As noted above, we will also consult specifically on any material departures from the assumptions book when

we consult on high-value BBI customer allocations and the simple method parameters (clause 17(4) of the proposed TPM).

18.2 Rationale – assumptions book

353. As required by clause 1(b) of the Guidelines, we considered the costs and benefits of a highly precise BBC methodology against practical considerations. Given the complexity of the BBC, we considered that developing a highly precise BBC methodology would not result in a robust methodology. In other words, there would be a high risk that such a methodology would not be broadly proportional to net-private benefits in all situations. We expect the precise methodology to develop over time as we apply it in practice, and amending the TPM is a costly exercise for the Authority, Transpower, and stakeholders. We consider a more flexible approach is necessary.

354. In the absence of a highly precise BBC methodology and set of input assumptions, we are proposing the TPM requires Transpower to produce an assumptions book, which will include a record of the assumptions and detailed processes under the simple and standard methods that do not change on an investment-by-investment basis. The assumptions book removes some discretion when we determine BBC allocations at a lower cost than the development of a highly precise TPM and with a lower risk of charges not being robust.

355. To the extent any assumption or methodology in the assumptions book proves resilient over time, such that it could be considered to form part of the BBC allocation or adjustment rules, it could be added to the TPM later as part of an operational review. As noted above, the proposed TPM requires us to review the assumptions book at least very seven years to identify any such content. The seven-year period is so there is sufficient time for assumptions book content to build up and to help avoid the reviews coinciding with our other regulatory processes happening on a five-yearly basis.

356. Importantly, as noted above, the contents of the assumptions book will need to be consistent with, and could not over-ride the requirements of, the TPM or anything else in the Code.

357. The assumptions book consultation requirements are designed to ensure transparency, accountability and stakeholder involvement. If a customer or other person considers the assumptions book, or our application or non-application of the assumptions and methodologies in it, is inconsistent with the TPM or anything else in the Code, the normal Code breach processes will apply.

358. We note the assumptions book (or something like it) will likely exist for our internal operational and decision-making purposes whether or not it is referred to in the TPM. This will be to ensure consistency in our decision-making and help customers anticipate and understand how we will go about allocating and adjusting BBCs. Referencing the assumptions book in the TPM allows consultation and publication obligations to attach to it (as outlined above), which will help safeguard transparency and benefit all stakeholders.

359. We have considered the option of the Authority having approval rights over the assumptions book. On balance, we do not consider Authority approval would be

appropriate given the technical content of the assumptions book, which we consider is best developed with industry through the consultation process. Generally, we do not consider it appropriate for the Authority to have a direct role in the day-to-day operation of the TPM.

360. The Australian Energy Market Commission has published a Rule Drafting Philosophy to guide it in making rules for the Australian National Energy Market.[101] The Rule Drafting Philosophy refers to finding an appropriate balance between prescription and principle in the rules and supports the use of guidelines outside the rules where appropriate. We consider the following extract from the Rule Drafting Philosophy captures the reasons why the assumptions book is appropriate:[102]

> It may be appropriate for Rules to provide for guidelines or procedures in the following circumstances:
>
> - matters where there may be several acceptable means for regulated parties to achieve the particular outcome specified in the Rules
> - matters where industry experience may develop over time
> - matters which require frequent adaptation to changes in such things as technology and communications
> - matters where detailed procedural matters can be left to the relevant regulatory entity to develop in consultation with industry
> - matters that are suited to industry standards or processes developed or applied by a body more closely associated with the management and operations of an industry, but only to the extent that a conflict of interest would not likely arise.

361. Most submitters on our BBC options consultation did not comment on the assumptions book. NZIER for MEUG supported its development.

19 Consistency with the Guidelines

362. Our proposal for the BBC allocation method is fully compliant with the Guidelines, with the exception of our proposal to assess benefits over a maximum of 20 years rather than the remaining life of the of the BBI (explained in Section 13.1).

363. Other than this, we have not proposed to use clause 2 to enable the TPM to differ in its details from the particular requirements in these Guidelines. Therefore, because the Guidelines were developed by the Authority and we have complied with the Guidelines, we also consider this proposal to be compliant with the Authority's statutory objective.

19.1 Our BBC proposals are consistent with the Guidelines

364. The Guidelines require the BBC methods in the new TPM (both standard and simple methods) to result in an allocation between designated transmission customers that is broadly in proportion to their expected positive net private benefits (EPNPBs) (clause 8

[101] AEMC, Rule Drafting Philosophy, 8 October 2020.
[102] AEMC, Rule Drafting Philosophy, 8 October 2020, page 10.

of the Guidelines), and that the calculation of benefits must be aligned with the treatment of electricity market benefit or cost elements under the Capex IM investment test (clause 23 of the Guidelines) unless Transpower considers such alignment would not result in allocations in proportion to EPNPBs. In our opinion our BBC standard and simple method proposals are consistent with these requirements.

365. In developing the BBC methodology, we note there is no objective measure of the benefit a customer receives from a transmission investment, even after the fact, as articulated by the Authority's description of the method it used to determine the Schedule 1 allocations using vSPD: "*running the vSPD model requires making input assumptions. In many cases we have applied judgement in selecting an appropriate assumption – particularly in respect of describing the counterfactual case (that is, what would have happened over the long term had the investment in question not been built).*"[103] This use of judgement is evident from the wide variation in outcomes under different iterations of the Authority's benefit modelling of the Schedule 1 investments.[104]

366. In other words, the economic benefits of a transmission investment can only ever be assessed against a hypothetical future that did not occur. This is different from (for example) an investment in a generation station that – due to the existence of the electricity market – receives tangible revenue that can be assessed after the fact against the cost of the investment.

367. Given there is no objective measure of benefits, the practical solution is to indirectly estimate benefits. All benefit quantification methods are – to some extent – a proxy or estimation of the benefits customers will receive from the investment. That said, clearly some proxies will better represent benefits than others.

368. Given this context, and as explained throughout this chapter, we consider our BBC proposal gives Transpower the ability to produce allocations that are broadly in proportion to expected positive net private benefits (noting, as we have throughout, the importance of the assumptions in any methodology). The CUWLP and WUNIVM case studies, and simple method allocations included in our indicative pricing (see Appendices B to E) are examples of the application of our proposal, and we consider these results to be broadly in proportion to expected positive net private benefits (subject to consultation on the assumptions and resulting charges).

369. In complying with clauses iv and 8 of the Guidelines, we have considered the costs and benefits of precision with the practical considerations in 1(b). For the proposed price-based method for quantifying market benefits under the standard method, we have allowed for all the key dimensions of private benefits to be considered in the final allocation (changes in market price, quantities, and operational costs) where these are material for a given BBI. However, using clause 50A of the proposed TPM, we have also allowed for the proportion of benefits to each regional beneficiaries to be based on the quantities during periods of benefit, where we this will result in allocations that

103 Document reference #1 2019 Issues paper, paragraph H.33.

104 For example, in Figures 30 and 31 of the 2016 Issues Paper, NZAS were modelled as receiving no positive net private benefits from Pole 2 and Pole 3, whereas in the 2019 Issues paper NZAS were modelled as receiving 7.25% of positive net private benefits of the HVDC.

are broadly proportional to EPNPB. Like any economic model, we have introduced other simplifying assumptions into the framework, in particular aggregating beneficiaries into regions and simplifying the grid using the investment grid concept. We consider the proposed price-based method balances precision (i.e. is reflective of expected positive net private benefits) with the practical considerations of 1(b)), to the extent possible within and consistent with the Guidelines.

370. However, without these simplifying assumptions (e.g. the use of 50A where appropriate, regional aggregation, and the investment grid), we think there is a high risk of the results not being robust (clause 1(b)(i) of the Guidelines), to the point where they risk allocation results not being broadly proportional to EPNPB. Furthermore, without the simplifying assumptions, we do not think the economic benefits of precision would outweigh the costs to Transpower of administering and complying with such a TPM, and more importantly, the costs our customers would incur understanding and engaging with the TPM.

19.2 Calculation period for the price-quantity method

371. As noted above, we propose to depart from the requirements of clause 21 of the Guidelines by assessing net private benefits from a BBI under the price-quantity method (being a standard method) over a maximum period of 20 years after the expected full commissioning date of the BBI.[105] The "remaining life" of the BBI when it is fully commissioned will likely be several decades longer.

372. We consider this departure is justified under clause 2 of the Guidelines.

372.1 We consider the departure is not inconsistent with the intent of the Guidelines. Under clause 8 of the Guidelines, the price-quantity method (and the resiliency method and simple method) must result in an allocation that is broadly in proportion to EPNPBs. A 20-year analysis period achieves this because, beyond 20 years, costs and benefits are uncertain, particularly private costs and benefits. Assessing and quantifying those distant costs and benefits is unlikely to make the final allocation more reflective of EPNPBs. In any event, the present values of distant costs and benefits would be low and would have relatively little impact quantitatively on the final allocation. A 20-year analysis period is also consistent with the investment test under the Capex IM, and therefore assists with complying with clause 23 of the Guidelines.

372.2 We consider the departure promotes the efficiency limb of the Authority's statutory objective. Estimating EPNPBs over many decades, potentially 55 years, would increase the cost of administering and complying with the new TPM and not produce a significantly better outcome, or any better outcome. For example, MBIE's EDGS do not extend out this long into the future, and therefore either Transpower or MBIE would need to develop the necessary load and generation forecasts.

105 Under the resiliency method, which is also a standard method, net private benefits are not explicitly assessed over any set period. The individual NPBs calculated under the resiliency method, which are based on mean historical annual offtake, are implicitly assumed to reflect individual NPB over the whole life of the relevant BBI. We therefore do not consider the resiliency method departs from the requirements of clause 21 of the Guidelines.

372.3 The departure is also consistent with the principle in clause 1(b) of the Guidelines (balancing practical considerations, including robustness, simplicity, certainty and cost, with the costs and benefits of precision). As noted above, we do not consider having a longer calculation period will assist with precision in terms of making final allocations more reflective of EPNPBs.

20 Example of constraint process for the investment grid

373. An indication of the modelled constraint process for the investment grid to be used in the market model for thermal-related BBI is provided below.

374. Voltage stability and transient stability constraints are more BBI dependent.

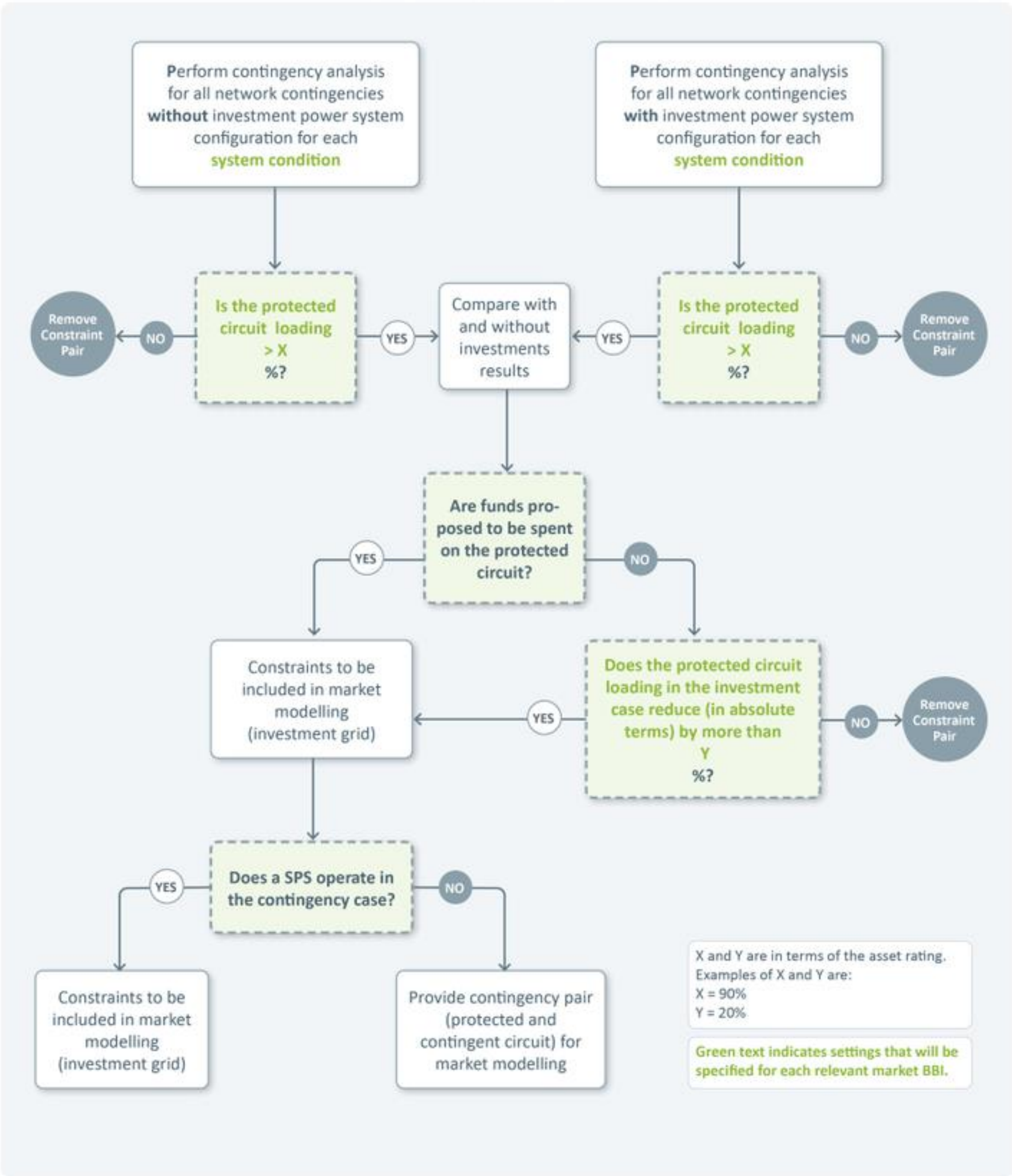


Figure 28 Example of constraint process for modelled thermal constraints

21 Example of process for the Simple method region definition

375. The following describes the process used to develop the regions for the simple method using 5 years of historical market branch flows for the indicative pricing calculations.

376. HV refers to voltage levels greater than or equal to 220kV and LV refers to voltage levels less than 220kV.

377. High voltage (HV) region definition process:

377.1 The HVDC is a region

377.2 HV-HV boundaries are at HV boundary buses for the largest region at which there is prevailing power flows. Boundary buses have:

377.2.1 prevailing flows at one end (consistent with the flow direction on the transmission interface[106] for at least 95% of the periods) and

377.2.2 variable flows on the other end (Variability flows are if 5th percentile and 95th percentile of the branch flow have the opposite flow sign)

378. Low voltage (LV) region definition process:

378.1 These are LV nodes and branches from the interconnecting substation (including the interconnection transformer)

378.2 Electrically connected LV regions can be split into adjacent LV regions if:

378.2.1 Connected to different HV regions

378.2.2 Connected to the same HV region but is not a strong connection relative to the parallel-connected HV region[107]

379. LV-LV boundaries are minimum transfer branches. These are branches:

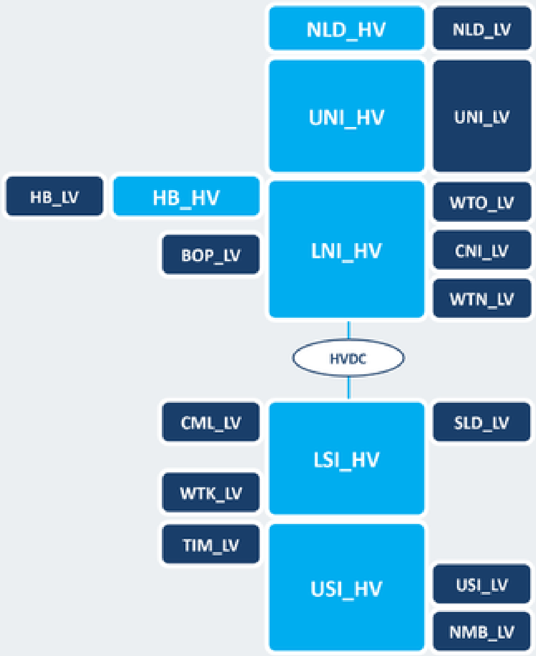
379.1 with lowest average flow magnitude between the adjacent LV regions and

379.2 if removed would electrically separate the adjacent LV regions.

380. The regions resulting from applying the above process is shown in Figure 29 of this chapter.

[106] An interface is a collection of high voltage circuits which if removed disconnect the HV system (Note there may still be an electrical connection via the LV system).

[107] A power flow transfer test is used to assess the strength of the LV network relative to the parallel HV network between corresponding HV-LV connection points. This is done by injecting 10MW at the HV bus at the relevant interconnection transformer bus, extracting 10MW at the LV bus of an interconnecting transformer and recording the change in flow (due to the injection and offtake) on the minimum transfer branch on the LV network between the relevant injection and offtake points. If the change in flow on the minimum transfer branch is less than 1MW for a 10MW injection/offtake we consider the LV connection weak relative to the HV connection. This is assessed using a DC load flow model.



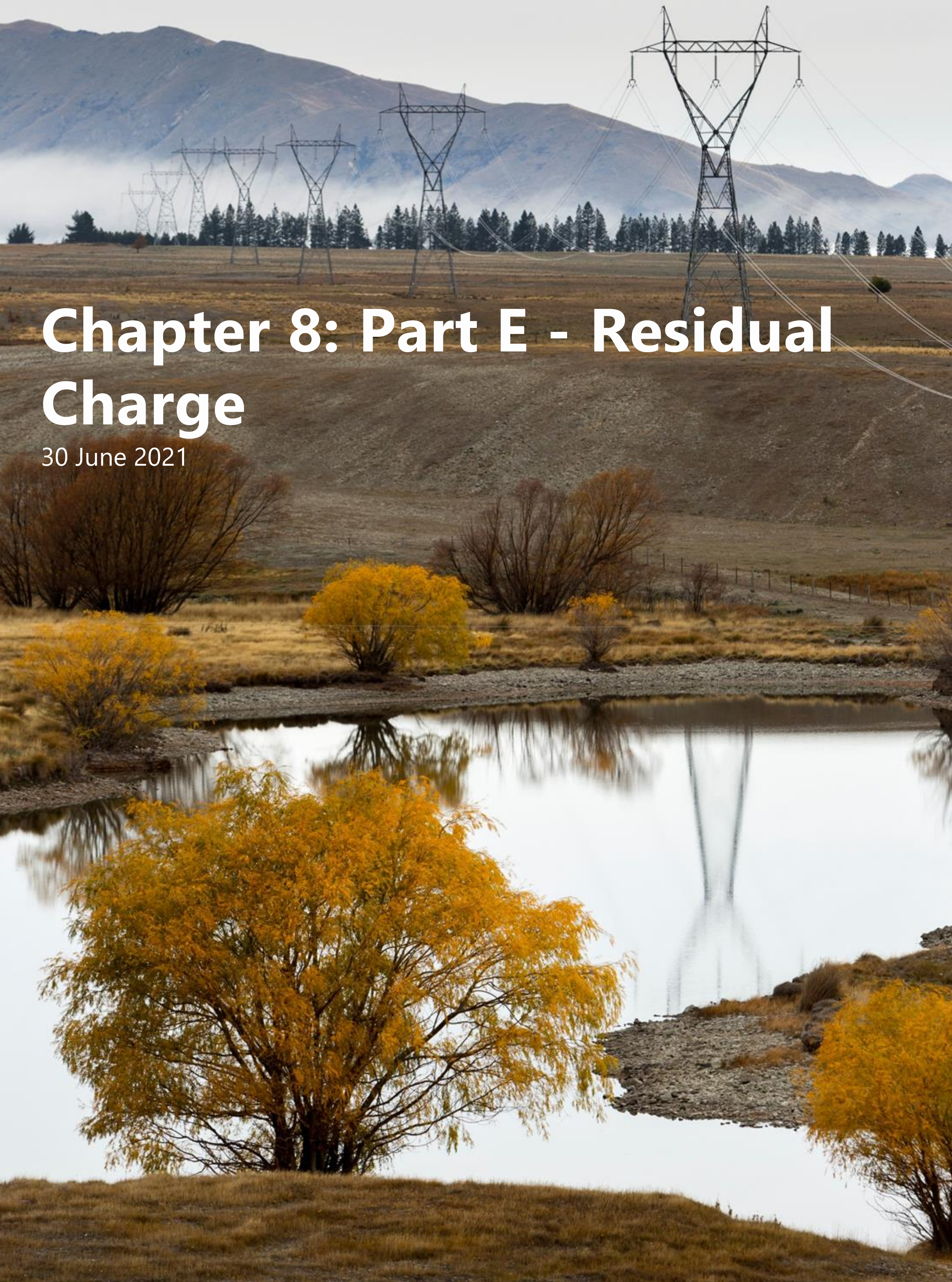
Region ID	Region Description
NLD_HV	Northland high voltage
UNI_HV	Upper North Island high voltage
LNI_HV	Lower North Island high voltage
HB_HV	Hawke's Bay high voltage
LSI_HV	Lower South Island high voltage
USI_HV	Upper South Island high voltage
HVDC	HVDC link
NLD_LV	Northland low voltage
UNI_LV	Upper North Island low voltage
WTO_LV	Waikato low voltage
CNI_LV	Central North Island low voltage
WTN_LV	Wellington low voltage
HB_LV	Hawkes Bay low voltage
BOP_LV	Bay of Plenty low voltage
SLD_LV	Southland low voltage
CML_LV	Cromwell low voltage
WTK_LV	Waitaki low voltage
TIM_LV	Timaru low voltage
USI_LV	Upper South Island low voltage
NMB_LV	Nelson-Marlborough low voltage

Figure 29 20-region network produced using the regional definition process under the Simple method

TRANSPOWER

Chapter 8: Part E - Residual Charge

30 June 2021



Contents: Chapter 8

1 Introduction

1. This chapter summarises and explains our proposals for the residual charge provisions of the proposed new TPM.
2. Residual charges recover the part of our recoverable revenue that is not recovered through other transmission charges ("residual revenue"). Residual charges are paid by load customers only, in proportion to their gross historic anytime maximum demand. As discussed below, we propose to include grid-connected generators with embedded load as load customers and allocate them a residual charge for that load.
3. At least initially, residual charges will recover the part of our recoverable revenue attributable to pre-2019 investments in the interconnected grid that are not included in Schedule 1 of the Guidelines/Appendix A of the proposed TPM. This is because we are not proposing to implement additional component E of the Guidelines (including additional pre-2019 investments in the benefit-based charge) from the start of the new TPM. This is discussed in Chapter 14 (Additional components).

2 Requirements of the Guidelines

4. Clause (v) of the Guidelines states the purpose of the residual charge.

> The purpose of the **residual charge** is to provide a mechanism to ensure that <u>Transpower</u> can recover up to its **recoverable revenue** in any **pricing year** in a way which is designed to minimise any effect on <u>designated transmission customers'</u> decision-making.

5. The residual charge is main component 3 of the Guidelines (clauses 27 to 30).

> **Main component 3: residual charge**

27. The **TPM** must provide for a **residual charge** to apply to all designated transmission customers, to the extent that they are **load customers,** to allow Transpower to recover any remaining **recoverable revenue** not recovered through other **transmission charges**.

28. The **TPM** must provide for the **residual charge** to be initially allocated in proportion to each designated transmission customer's historical anytime maximum demand, which may be calculated using data supplied by the reconciliation manager, and is to be calculated by:

    a. taking**,** in a year from 1 July to 30 June, the customer's anytime maximum demand for that year, which is calculated by:

        i. for each one of the customer's points of connection, taking the highest value in any trading period in that year of gross load, being the sum of:

            1. the net quantity of electricity flow from the grid at that point of connection; and

            2. Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection; and

        ii. aggregating each of those sums across all the customer's points of connection;

    b. taking the average of the customer's anytime maximum demand over the four years from 1 July 2014 to 30 June 2018.

29. The **TPM** must provide that, in initially allocating the **residual charge** under clause 28, Transpower may adjust the allocation where necessary to accommodate circumstances in which, in Transpower's reasonable opinion, a designated transmission customer has experienced a substantial reduction in anytime maximum demand, due to factors that are largely beyond the customer's control or influence. For the purposes of this clause, a substantial reduction in demand is to be assessed relative to the designated transmission customer's remaining demand.

30. The **TPM** must provide that for each **pricing year**, from and including the **pricing year** commencing on 1 April 2023, the **residual charge** is to be allocated in proportion to each designated transmission customer's adjusted historical anytime maximum demand, calculated as:

$$AHAMD_t = HAMD_0 \times U_t / U_0$$

where:

$AHAMD_t$	is the designated transmission customer's adjusted historical anytime maximum demand
$HAMD_0$	is the designated transmission customer's historical anytime maximum demand calculated as described in clauses 28 and 29.
U_t	is the designated transmission customer's average total **gross** annual energy usage (measured in MWh) across the year commencing on 1 July four years and nine months prior to the start of the **pricing year** in which the adjustment

applies and the three preceding years commencing on 1 July

U0 is the designated transmission customer's average total **gross** annual energy usage (measured in MWh) across the four years from 1 July 2014 to 30 June 2018, reduced as necessary to be consistent with the reduction in anytime maximum demand under clause 29.

6. The definitions of "gross" and "load customer" in the Guidelines are also relevant.

> **gross**, in relation to a **load customer's** energy usage means total energy usage on the **load customer's** network, being the sum of:
>
> 1. the customer's off-take from the grid;
> 2. Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection.
>
> **load customer** means a designated transmission customer whose equipment draws electricity from the grid or from any generation behind the designated transmission customer's point or points of connection (including distributed generation and behind-the-meter generation).

3 Stakeholder engagement and process

3.1 Consultation

7. We did not initially consult on options for residual charges. The Guidelines are prescriptive about the method for residual charges, so there is limited scope for us to consider different options. We chose to focus our stakeholder engagement on other matters.

8. In December 2020, as part of its feedback on our Checkpoint 2A submission (see below), the Authority invited us to consider the application of residual charges to grid-connected batteries.

9. In March 2001, we released a consultation paper seeking feedback on options for applying residual charges to batteries (our batteries consultation paper). Our proposal for applying residual charges to batteries is discussed in Chapter 9 (Residual charges and batteries) of this paper.

10. Our batteries consultation paper, submissions and cross-submissions are published on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[1]

11. We have taken the submissions and cross-submissions on our batteries consultation paper into account in preparing the proposed TPM.

[1] TPM Development: Batteries and the Residual Charge consultation process

3.2 Checkpoint 2

12. In November 2020, we submitted our preliminary proposals for residual charges to the Authority as part of its Checkpoint 2 process (our Checkpoint 2A submission).[2] Our Checkpoint 2A submission included preliminary TPM drafting for residual charges.

13. In its feedback on our Checkpoint 2 submission,[3] the Authority said it considered most of our preliminary proposals for residual charges to be appropriate, but there were some technical aspects to be addressed. In the Authority's view, to be consistent with the Guidelines:

    13.1. *"generation with embedded load should be allocated a share of the residual charge";* and

    13.2. *"the residual charge allocation should change only gradually, after a lag, in response to changes with respect to existing customers' plant (not a step change)."*[4]

14. As noted above, the Authority invited us to consider the application of residual charges to grid-connected batteries, and said it did *"not currently have a view on this question"*. The Authority also provided feedback on some more minor issues.

15. We resubmitted our preliminary proposals for residual charges to the Authority in January 2021, responding to the matters the Authority had raised (our Checkpoint 2A resubmission).[5] In response to our Checkpoint 2A resubmission, the Authority provided further feedback on the application of residual charges to generators and some other matters.

16. In March 2021 and May 2021, we submitted further preliminary TPM drafting to the Authority as part of its Checkpoint 2 process (Checkpoint 2B submission and resubmission).[6] In response to our Checkpoint 2B resubmission, the Authority provided some feedback on the preliminary TPM drafting.

17. We have taken the Authority's feedback on our Checkpoint 2 submissions and resubmissions into account in preparing the proposed TPM.[7]

4 Summary of our proposal

18. As noted above, the Guidelines are prescriptive about the method for residual charges. Part E of the proposed TPM implements the method in the Guidelines with one departure (discussed in Sections 5 and 7).

---

[2] Reference document #31 Checkpoint 2 submission: Residual Charge and Transitional Cap

[3] Reference document #35 Letter from EA: Checkpoint 2A submission

[4] This aspect of the Authority's feedback is discussed in Chapter 10 (Adjustments).

[5] Reference document #42 Checkpoint 2 resubmission: Residual Charge and Transitional Cap

[6] Reference document #52 Checkpoint 2B submission: preliminary TPM drafting and Reference document #64 Checkpoint 2B submission: preliminary TPM drafting

[7] Authority staff suggested, in response to the preliminary TPM drafting we submitted with our Checkpoint 2B submission, the "whole of life" approach is relevant to residual charges. We think the Authority was referring to clause 33(b) of the Guidelines, which only applies to benefit-based charges.

19. In summary, we propose:

    19.1. The initial (baseline) allocation of residual charges will be in proportion to load customers' gross historical anytime maximum demand (kW), averaged across four historic financial years (financial years 2014 to 2017) (clause 67(1) of the proposed TPM).[8] For a recent or new load customer, we will estimate this allocator (discussed in Section 6).

    19.2. We may adjust a load customer's initial allocation if there has been a sustained reduction in the customer's maximum gross demand after the end of financial year 2017 due to any event or circumstance beyond the customer's control (clause 69 of the proposed TPM and the proposed definition of "reduction event"). We propose to apply a threshold of 10 MW to this, for consistency with our proposed threshold for "large"[9] and because we consider our customers will expect changes of this magnitude to be reflected in the initial allocation of their residual charges. In terms of clause 29 of the Guidelines, we consider 10 MW to be a "substantial reduction" relative to anything, including the customer's remaining demand.

    19.3. The initial allocation of residual charges will be adjusted annually based on lagged gross annual energy usage (kWh) over the period of four financial years commencing eight years ago (clauses 66 and 68 of the proposed TPM).[10] For a recent or new load customer, the lagged adjustments will not start until a full sample of historic gross annual energy usage for the customer is available (clause 68(1)(a)(ii) of the proposed TPM).

20. There are some minor differences in terminology between the Guidelines and the proposed TPM, as shown in the following table. Some of these differences are largely to retain language used in the current TPM.

---

[8] As contemplated in clause 28 of the Guidelines, we may obtain some of the data necessary to calculate gross historical anytime maximum demand from the reconciliation manager. We may also obtain some of the data from other sources, and will need to do so for embedded load and generation data the reconciliation manager does not have.

[9] The "large" threshold is discussed in Chapter 10 (Adjustments).

[10] To avoid a divide by zero error in the calculation of RCAF, we propose a minimum value for ATGE baseline of 1 kWh (clauses 68(3) and (4) of the proposed TPM).

Guidelines term/variable	Equivalent TPM term/variable
Load customer	Offtake customer
Various measures of gross load	Gross energy (kWh) Total gross energy (kWh) Maximum gross demand (kW)
Historical anytime maximum demand, $HAMD_0$	Anytime maximum demand (residual) baseline, $AMDR_{c\ baseline}$ (kW)
Adjusted anytime maximum demand, $AHAMD_t$	Anytime maximum demand (residual), $AMDR_{cn}$ (kW)
Average total gross annual energy usage, U_t and U_0	Lagged average total gross energy, $LATGE_{cn}$ Average total gross energy baseline, $ATGE_{c\ baseline}$
U_t/U_0	Residual charge adjustment factor, $RCAF_{cn}$

21. The following Sections discuss two aspects of our proposal where we have some discretion, including how our thinking has evolved.

5 Grid-connected generators with embedded load

22. As required by the Guidelines, the proposed TPM defines "load customer" by reference to gross energy, which includes different types of electricity embedded behind a customer's point of connection to the grid (not just grid offtake). As a result of these requirements, there may be instances where a customer who does not take electricity off the grid will nevertheless be considered a "load customer" and will therefore be liable to pay a residual charge on a gross load basis.

23. The proposed definitions of "load customer", "embedded electricity", "gross energy" and "maximum gross demand" (the latter being the underlying allocator for residual charges) in the proposed TPM are intended to clarify and address this. The different types of load customers are also illustrated in clause 5(1) of the TPM, which is extracted below:

5 Load Customers, Gross Energy and Maximum Gross Demand

(1) The different types of **load customer** are shown in figures 1, 2 and 3. In figures 1, 2 and 3, "LN" means **local network**, "CP" means **consuming plant**, "GP" means **generating plant**, "NGN" means **non-grid network** and "POC" means **point of connection** to the **grid**:

(a) In figure 1, a **customer** owning or controlling LN, CP or GP is an **offtake customer** to the extent of the **offtake**:

(b) In figure 2, a **customer** owning or controlling LN or CP is a **supplied load customer** to the extent of the **embedded electricity**. The **embedded electricity** is referred to as the **supplied load customer's embedded electricity** "at" the POC and relevant **connection location**:

(c) In figure 3, a **customer** owning or controlling GP is a **supplying load customer** to the extent of the **embedded electricity**. The **embedded electricity** is referred to as the **supplying load customer's embedded electricity** "at" the POC and relevant **connection location**:

Figure 1

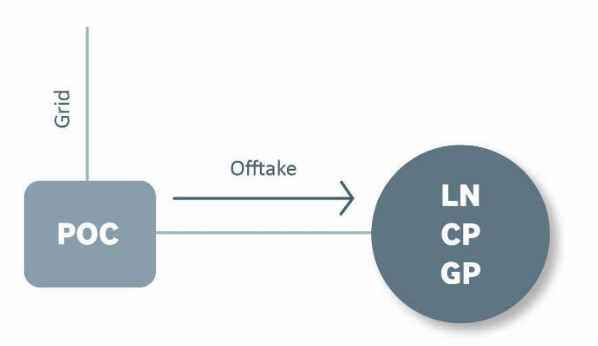


Figure 2

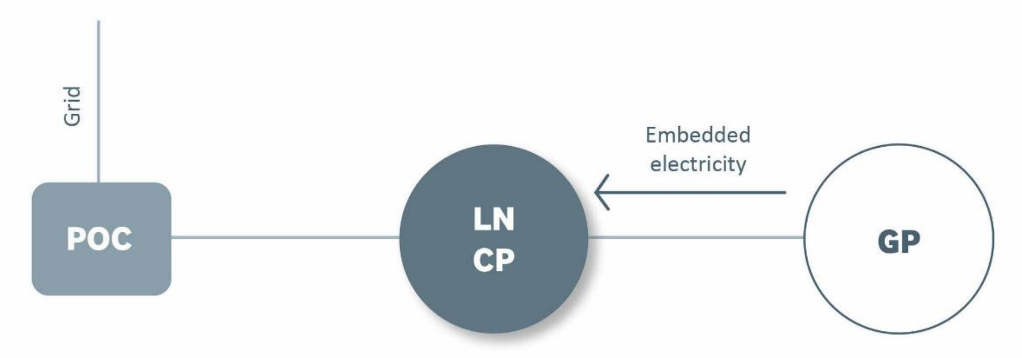
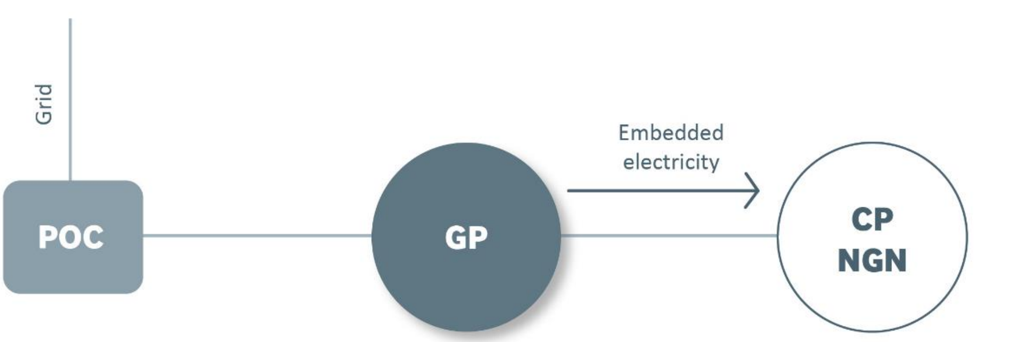


Figure 3



24. In clause 5(1)(c) and figure 3 of the proposed TPM, we propose to include grid-connected generators with embedded load ("embedded electricity") as load customers (specifically, "supplying load customers"). Under clauses 5(3) and (4) of the proposed TPM, a grid-connected generator's embedded electricity counts towards its "gross energy" and "maximum gross demand". A grid-connected generator will therefore be allocated a residual charge for its embedded electricity (and its grid offtake).

25. In our Checkpoint 2A submission, we initially did not propose to capture grid-connected generators with embedded load as load customers. In paragraphs A.6 and A.7 of its feedback on our Checkpoint 2A submission, the Authority expressed concern with this approach: *"This omission could encourage customers to structure their connection arrangements in order to avoid paying transmission charges"* and confirmed

its view that that grid-connected generators should pay a residual charge in respect of their embedded load.[11]

26. The Authority reiterated that view again in response to our Checkpoint 2A resubmission:

> The Authority does not, however, share Transpower's view that it would be necessary to depart from the detail of the 2020 TPM guidelines using clause 2 in order to apply the residual charge to generators with embedded load. We remain of the view that the guidelines do require the application of the residual charge to load behind generation, by virtue of clause 7.
>
> On this basis, the Authority's view is that Transpower's proposed TPM should therefore provide for generation with embedded load to be allocated a share of the residual charge.
>
> In any case though, the Authority's view is that allocating a share of the residual charge to generators with embedded load would avoid distorting location decisions by load, which might otherwise be encouraged to inefficiently locate behind generation in order to avoid the residual charge. As such, we consider the proposed approach is necessary to satisfy the principle included at clause 1(c) of the Guidelines.[12]

27. We reconsidered and further developed our proposal in light of the Authority's feedback on our Checkpoint 2A submission and resubmission.

28. In our view, our proposal to include grid-connected generators with embedded load as load customers and allocate them a residual charge for that load is a departure from the requirements of the Guidelines:

    28.1. Clause 27 of the Guidelines says designated transmission customers pay residual charges *"to the extent that they are load customers"*, not *"to the extent that they have load"* (the words the Authority used in paragraph A.7(a) of its feedback on our Checkpoint 2A submission). This is an important difference because "load customer" is defined in the Guidelines in a way that does not capture generators with embedded load (in that the generator is not drawing electricity from the grid or from other generation behind the point of connection, and the party with the embedded load is not a designated transmission customer in its own right).

    28.2. The HAMD calculation in clause 28(a) of the Guidelines does not capture the embedded load being supplied by the generator.

    28.3. The definition of "gross" in the Guidelines does not capture the embedded load being supplied by the generator.

29. While we acknowledge the Authority's view, for the reasons stated above we have treated this as a departure from the requirements of the Guidelines listed above.[13] This departure is discussed further in Section 7.

---

[11] Reference document #35 Letter from EA: Checkpoint 2A submission

[12] Reference document #44 Letter from EA: Checkpoint 2A resubmission Residual Charge and Transitional Cap

[13] The Authority's interpretation is based on clause 7 of the Guidelines. The Authority's interpretation does not engage the definitions of "load customer" or "gross" in the Guidelines or any of the clauses relating directly to residual charges. We do not consider clause 7 is relevant because it is about equipment connected through *"the designated transmission customer's*

6 Recent and new load customers

30. Clause 33(c) of the Guidelines requires Transpower to allocate a residual charge to a new load customer that is:

> ultimately…equivalent to the charge that would, in <u>Transpower's</u> reasonable opinion, have been payable had the **large offtake plant**, **large generating station** or <u>designated transmission customer</u> been fully operational from 1 July 2014.

31. In the proposed TPM we have extended this requirement to "recent load customers", which includes load customers who are "new" in the sense they have not been load customers for the whole of period required to be a "pre-existing load customer" (financial year 2014 to financial year 2017).

32. We propose:

    32.1. A recent or new load customer's AMDR baseline will be estimated taking into account the capacity of the customer's assets, the AMDR baselines for comparable load customers and (for a recent load customer) any historical information about the customer's maximum gross demand (clauses 67(2)(a) and 91(2)(a) of the proposed TPM). This estimation will be done assuming full operation of the assets from the start of financial year 2014.[14]

    32.2. We will have a limited ability to adjust a recent or new customer's AMDR baseline after initially setting it (clauses 67(2)(b) and 70 of the proposed TPM). As noted in clause 70(2) of the proposed TPM, the purpose of such an adjustment would be to correct any material under or over-estimation of the AMDR baseline.

33. In our Checkpoint 2A submission we questioned whether our proposal to reopen the estimate (and our previous proposal to assume less than full operation) is a departure from the requirements of clause 33(c) of the Guidelines, as we were unclear about the significance of the word *"ultimately"*.

34. In response to our Checkpoint 2A submission, the Authority confirmed that *"the proposal is consistent with the guidelines, (i.e. is not a departure), given that cl 33(c) of the guidelines gives Transpower some flexibility regarding the residual charge for new customers, providing that, in the long run, the charges ultimately result in the customer paying residual charges equivalent to those they would have received if they had been fully operational from 1 July 2014"*. The Authority also confirmed it *"had no substantive concerns"* with this proposal.

---

network". A generating station is not a network, and the lines that connect a generating station to the grid are not a network (as defined in the Code) either. In any event, we do not consider clause 7 can override otherwise unambiguous definitions in the TPM, including because clause 7 is not relevant to overall interpretation under clause 3 of the Guidelines.

14 Our preliminary proposal was to reserve a right not to assume full operation. We now consider it is better to have one rule for all, and a standing assumption of full operation from financial year 2014 is consistent with clause 33(c) of the Guidelines.

7 Consistency with the Guidelines

35. Except for the matter discussed below, we consider our proposals for residual charges are fully compliant with the Guidelines. See the Guidelines compliance matrix attached to this paper.

7.1 Grid-connected generators with embedded load

36. As noted above, we consider our proposal to include grid-connected generators with embedded load as load customers and allocate them a residual charge for that load is a departure from the requirements in the Guidelines.

37. We consider this departure is justified under clause 2 of the Guidelines.

    37.1. We consider the departure is not inconsistent with the intent of the Guidelines. The Guidelines do not expressly address the scenario where a generator has embedded load. The Authority's 2020 Decision[15] and earlier papers, such as the 2019 Issues Paper,[16] are also silent on this specific issue. However, the Authority's feedback on our Checkpoint 2A submission and resubmission establishes the Authority does intend the residual charge to apply to generators in respect of their embedded load, consistent with a broader policy intent to avoid incentives for parties to structure their arrangements in ways that avoid transmission charges. This is also consistent with the Authority's decision that residual charges be calculated on the basis of gross energy i.e. overall load.[17]

    37.2. We consider the departure promotes both the efficiency and competition limbs of the Authority's statutory objective. Without the departure, a party that would otherwise be a load customer could be incentivised to connect its consuming plant or network behind a grid-connected generator in order to avoid a residual charge, even if it would be more efficient overall for the party's consuming plant or network to be grid-connected. Also, without the departure, competitive neutrality between grid-connected and embedded consumers and network owners could be compromised because the grid connected parties would pay residual charges whereas the embedded parties would not.

38. The departure is also consistent with the principles in clauses 1(b) and 1(c) of the Guidelines (practical considerations and avoiding incentives to inefficiently avoid transmission charges). The practical consideration is that for some consuming plant/generating plant configurations it may be difficult to determine whether the consuming plant or generating plant is connected directly to the grid. The departure makes that distinction academic (clause 5(2) of the proposed TPM).

---

15 Reference document #3 2020 Decision

16 Reference document #1 2019 Issues paper

17 Noting that the definition of "gross" in the Guidelines fails to fully capture all elements of load the Authority evidently intended to capture.

TRANSPOWER

Chapter 9: Part E – Residual Charges (Treatment of Batteries)

30 June 2021

Contents: Chapter 9

1 Introduction

1. This chapter summarises and explains the reasons for the application of the residual charge to grid-connected batteries under the proposed new TPM.

2 Requirements of the Guidelines

2. Clause (v) of the Guidelines states the intent of the residual charge:

> The purpose of the **residual charge** is to provide a mechanism to ensure that Transpower can recover up to its **recoverable revenue** in any **pricing year** in a way which is designed to minimise any effect on designated transmission customers' decision-making.

3. The residual charge is main component 3 of the Guidelines (clauses 27 to 30):

> **Main component 3: residual charge**
>
> 27. The **TPM** must provide for a **residual charge** to apply to all designated transmission customers, to the extent that they are **load customers,** to allow Transpower to recover any remaining **recoverable revenue** not recovered through other **transmission charges**.
>
> 28. The **TPM** must provide for the **residual charge** to be initially allocated in proportion to each designated transmission customer's historical anytime maximum demand, , which may be calculated using data supplied by the reconciliation manager, and is to be calculated by:
>
> a. taking**,** in a year from 1 July to 30 June, the customer's anytime maximum demand for that year, which is calculated by:
>
> i. for each one of the customer's points of connection, taking the highest value in any trading period in that year of gross load, being the sum of:
>
> 1. the net quantity of electricity flow from the grid at that point of connection; and
>
> Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection; and

Front cover photo credit: Tesla

ii. aggregating each of those sums across all the customer's points of connection;

b. taking the average of the customer's anytime maximum demand over the four years from 1 July 2014 to 30 June 2018.

29. The **TPM** must provide that, in initially allocating the **residual charge** under clause 28, Transpower may adjust the allocation where necessary to accommodate circumstances in which, in Transpower's reasonable opinion, a designated transmission customer has experienced a substantial reduction in anytime maximum demand, due to factors that are largely beyond the customer's control or influence. For the purposes of this clause, a substantial reduction in demand is to be assessed relative to the designated transmission customer's remaining demand.

30. The **TPM** must provide that for each **pricing year**, from and including the **pricing year** commencing on 1 April 2023, the **residual charge** is to be allocated in proportion to each designated transmission customer's adjusted historical anytime maximum demand, calculated as:

$$AHAMD_t = HAMD_0 \times U_t \ / \ U_0$$

where:

$AHAMD_t$	is the designated transmission customer's adjusted historical anytime maximum demand
$HAMD_0$	is the designated transmission customer's historical anytime maximum demand calculated as described in clauses 28 and 29.
U_t	is the designated transmission customer's average total **gross** annual energy usage (measured in MWh) across the year commencing on 1 July four years and nine months prior to the start of the **pricing year** in which the adjustment applies and the three preceding years commencing on 1 July
U_0	is the designated transmission customer's average total **gross** annual energy usage (measured in MWh) across the four years from 1 July 2014 to 30 June 2018, reduced as necessary to be consistent with the reduction in anytime maximum demand under clause 29.

3 Stakeholder engagement and process

4. We did not initially consult on the residual charge or how it could be calculated. The method is prescribed in the Guidelines so there is limited scope for Transpower to consider different options for the application of the residual charge.

5. However, in December 2020, as part of its feedback on our Checkpoint 2 preliminary proposal for the residual charge, the Electricity Authority (**Authority**) invited us "*to consider whether it would better promote the Authority's statutory objective to largely exempt batteries from the residual charge, consistent with the treatment of other generation*" and noted "*the*

flexibility around the residual charge provided by clause 2 of the guidelines."[1] The Authority had also encouraged Contact Energy to engage with us on this matter.[2]

6. Given this was a new development with the potential to impact multiple parties, including those looking at potential battery/storage investments, we decided to consult with all stakeholders (not just engage with Contact) in order to respond appropriately to the Authority's feedback and give appropriate consideration to the issue.

7. The Authority subsequently clarified that it "*intends that any new TPM would not compromise competitive neutrality in the wholesale market, and that batteries/storage should be able to operate efficiently and contribute to the reliability of the grid. The Authority considers that it would most likely be inconsistent with its statutory objective (and it would certainly not be the Authority's intent) for the new TPM to discourage efficient investment in grid connected batteries.*"[3]

3.1 Consultation

8. In March 2020, we released a Residual Charges and the Treatment of Batteries Options Consultation paper on how the residual charge should be applied for batteries, and for grid-connected or embedded utility scale storage devices more broadly. The consultation paper, submissions and cross-submissions are published on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[4]

9. The consultation paper sought feedback on whether, and the extent to which:

   9.1 There are potential problems with the application of the residual charge to grid-connected batteries under the new TPM; and

   9.2 The TPM could or should provide for different treatment of grid-connected batteries with respect to the residual charge, e.g. through an exemption for grid-connected batteries when they are charging for storage.

10. In our summary and response document, we told stakeholders we had been unable to form the necessary "*reasonable opinion*" required by clause 2 of the Guidelines that departing from the Guidelines in respect of the application of the residual charge to batteries via options 2 or 3 (being a full or partial exemption from the residual) would better meet the Authority's statutory objective than complying with the Guidelines.[5]

3.2 Checkpoint 2

11. On 3 May 2021, we submitted our preliminary proposal for application of the residual charge to grid-connected batteries under the new TPM as part of the Authority's Checkpoint 2 process, including our detailed assessment and analysis of issues raised by stakeholders during the consultation. Our preliminary proposal was that the residual would apply to batteries, consistent with the Guidelines, and we would not apply clause 2 to deviate from the Guidelines.

---

1 Reference document #35 Letter from EA: Checkpoint 2A submission
2 Authority letter to Contact Energy Ltd, 16 November 2020.
3 Reference document # 54 Letter from EA: Batteries and the Residual Charge
4 TPM Development: Residual Charges and the Treatment of batteries consultation process
5 Reference document #66 Batteries and the Residual Charge: Summary and Response

12. In its feedback on our Checkpoint 2 submission, the Authority "*acknowledge[d] the significant effort that Transpower has put into its work on the issues around the application of the residual charge to batteries and similar storage*" and that "*Assuming Transpower's view in its Checkpoint 2c submission is retained in its 30 June 2021 proposed TPM, we expect that the Authority will need to further consider this policy issue in ensuring that the proposed TPM is consistent with our statutory objective and the guidelines, building on the work already undertaken by Transpower and the stakeholder views received. This will inform [the Authority's] response to Transpower's proposed TPM.*" [6]

4 Summary of our proposal

13. Transpower proposes to adhere to the requirements of the Guidelines such that:
    - 13.1 grid-connected batteries are treated as load customers for their entire offtake and embedded electricity under the new TPM; and
    - 13.2 clause 2 of the Guidelines is not applied to seek to deviate from the Guidelines in relation to treatment of grid-connected batteries.

5 Options assessment

14. We considered three options for application of the residual charge to grid-connected batteries: [7]
    - 14.1 **Option 1 (adhere to the Guidelines):** Grid-connected batteries are treated as load customers for their entire offtake and embedded electricity under the new TPM (supported by IEGA, MEUG, Nova, Powerco, Trustpower and Vector) (our TPM proposal);
    - 14.2 **Option 2 (clause 2 deviation):** Grid-connected batteries are exempted from the residual charge with respect to offtake and embedded electricity while charging, except as to losses (supported by Infratec, Meridian, Orion, and WEL); or
    - 14.3 **Option 3 (clause 2 deviation):** Grid-connected batteries are fully exempted from the residual charge with respect to offtake and embedded electricity while charging (supported by Contact, Mercury and Helios Energy).

5.1 Guidelines requirements and Authority intent

15. Options 2 and 3 would need to be implemented by way of a departure from the requirements of the Guidelines under clause 2.[8] Under clause 2, the TPM may depart from the requirements of the Guidelines if Transpower considers, in its reasonable opinion, departing from the requirements of the Guidelines:

---

6 Reference document #70 Letter from EA: Checkpoint 2C submission Batteries and the Residual Charge

7 In submissions, ETNZ, IEGA, Mercury, Nova, Orion, Trustpower, Vector and WEL proposed alternative options. These are detailed in our Summary and Response document, and include options that the Authority has already considered and disregarded such as net AMD and retention of RCPD, or which are not in scope for TPM development.

8 We have explored whether there is an alternative interpretation of the existing definitions in the Code that would permit Transpower to exempt grid-connected batteries from the residual charge, without the need for Transpower to rely on a departure under clause 2 of the Guidelines. We have not been able to identify a robust interpretative option.

15.1 would better meet the Authority's statutory objective than strictly complying with the Guidelines in their entirety; and

15.2 would not be inconsistent with the intent of the Guidelines.

5.2 Stakeholder views

16. Submitters on our battery consultation expressed disparate views on these options.[9] There was no consensus on how the residual charge should, or should not, apply to grid-connected batteries.

17. We received a number of submissions in support of option 1 and/or opposing options 2 and 3. For example:

17.1 IEGA: "*we query if this exception to treat one part of the solution (batteries) differently from equivalent solutions (distributed generation and cogeneration) is equitable or demonstrates a durable TPM methodology?*"

17.2 MEUG: "*MEUG does not believe there has been any evidence provided to justify treating batteries different from other load in relation to TPM residual charges*."

17.3 MEUG: "*An example of such a subsidy would be if grid-scale batteries were exempt from paying residual charges because of the peak-transmission saving benefit that batteries can deliver. However, existing large grid connected consumers with demand response can deliver the same benefit but must pay residual charges. It would be bizarre if an existing large grid connected consumer decided to quit New Zealand partly because of the residual charge only to have the peak transmission benefit provided instead by batteries exempt from residual charges.*"

17.4 Nova: "*Option 1 is the only equitable arrangement under the TPM in its current form*."

18. Powerco: "*The level of the residual charge is based on measures of gross demand. Option 1 preserves the option to treat equally any connection configuration involving consumption and injection, regardless of the combinations of technologies used.*"

18.1 Trustpower: "*…we think Option 1 is the only option presently available to Transpower*".

18.2 Trustpower: "*If Options 2 or 3 are adopted it will increase concerns about the prospect of the new TPM operating on the basis of very subjective judgments about relative equities.*"

18.3 Vector: "*Transpower's proposal options 2 and 3 to create a specific technology carve out for grid-connected battery load from charging activity creates the further risk of distortions. The effect of such an approach would be to provide an explicit discount for the transportation of energy to charge the grid-scale battery. Where a battery was used in the wholesale energy market this element would provide the grid-scale battery an unfair competitive advantage to other forms of generation which do not have any equivalent input (fuel) transportation subsidy.*"

19. One of the themes in submissions opposing options 2 and 3 is that the issues raised about batteries are part of a wider problem, and it would be ad hoc and discriminatory to deal with one element of the problem but not others. For example:

19.1 IEGA: "*we query if this exception to treat one part of the solution (batteries) differently from equivalent solutions (distributed generation and cogeneration) is equitable or demonstrates a durable TPM methodology?*" and "*The decision to apply an exemption for*

[9] TPM Development: Residual Charges and the Treatment of batteries consultation process, submissions and cross-submissions.

batteries would be inconsistent with all of the TPM process decisions (made over the many years of consultation) to include embedded distributed generation and cogeneration into the gross AMD calculation for allocating the residual charge against the views expressed in extensive submissions from industry participants".

19.2 MEUG: *"… it would be bizarre if end consumers that could provide identical services as a battery went out of business because they had to pay residual charges and batteries started up because they were exempt from paying residual charges. MEUG therefore does not agree that there are battery specific policy issues in relation to residual charges …"*

19.3 Nova: "*If consumers with embedded cogeneration are to be charged the residual charge based on their gross load then, in Nova's submission, there can be no justification for not applying the same charging basis for batteries, grid connected or otherwise" and "Just as "the TPM should not be written in a way that advantages current technologies relative to emerging ones*" (para 36), the TPM should also not advantage emerging technologies over existing investments. "*Just as proposed for batteries, cogeneration plants were built on the basis that they create no cost to the transmission system and provide an attractive alternative to further investment in grid capacity. The TPM at the time was specifically designed to ensure that the grid was paid for in direct proportion to the demands placed on the grid.*"

20. On the other hand, there were submissions in support of options 2 and 3:

20.1 Helios: "*For the avoidance of doubt, Helios believes that the round-trip losses faced by the battery, i.e. the difference between the consumed energy to charge the battery and the discharged energy from the battery should be exempt from the Residual Charge. This is an important part of the fuel cost faced by the battery owner and is no different from the conversion efficiency of fuel to electricity for other generators. To impose the Residual Charge on this component would lead to a distortion in the Fuel Cost the battery owner faced and therefore would need to be passed on via their offer price for services provided during discharge.*"

20.2 Mercury: "*In the absence of other options Mercury supports Option 3 (full exemption for batteries when charging) at this stage as it is most likely to preserve competitive neutrality between technologies while minimising the administrative burden for Transpower.*"

20.3 Meridian: "*Meridian considers that if batteries are to be exempt from the residual charge that this should be partial, consistent with Transpower's option 2. To ensure a level playing field, we agree that battery losses should be covered by the residual charge in the same way as the electricity a non-battery generator consumes to run its plant.*"

20.4 Orion: "*Of the options listed in the paper we would prefer option 2. It is important to consider an appropriate counter-factual, and if the battery was not there, the considerable losses associated with charging and discharging would not occur. Option 3 would not provide an incentive for the operator to consider this loss in its operation of the battery.*"

20.5 WEL (supported by Infratec): "*We believe option 2 strikes an equitable balance between the interests of all industry participants, while critically maintaining the economic viability of large scale batteries. We believe option 1 will discourage the installation of large scale battery storage which will reduce competition benefits in the wholesale market and ancillary services markets and reduce alternatives to transmission options for* *investments by Transpower. Large scale batteries will increase the ability of the power system to accommodate large scale variable output renewable generation and can provide voltage support to the grid*."

5.3 Our assessment

21. There may be a basis for concluding option 2 or 3 would better support the Authority's statutory objective than option 1. We consider all three limbs of the statutory objective – competition, reliability and efficiency – are relevant.
22. We place weight on the role grid-connected batteries could play in New Zealand achieving its emissions reductions goals.
23. We are also mindful that the residual charge for grid-connected batteries would be neither benefit-based nor cost-based, and would be unavoidable. We consider gross AMD would be a problematic allocator for batteries, but it also raises issues for other types of load as well.
24. However, we also place weight on the views expressed by stakeholders in the consultation. Stakeholder views were disparate. Legitimate arguments have been raised both in favour and against Transpower attempting to address battery storage under clause 2.
25. When all matters are weighed together, we have been unable to reach with sufficient confidence the *"reasonable opinion"* threshold (as required by clause 2 of the Guidelines) that the Authority's statutory objective would be better supported by either option 2 or 3.
26. We have also considered the extent to which the Authority has indicated how it intends the residual charge to be applied to grid-connected batteries in the TPM. The Authority's letter to Transpower clearly indicates clause 2 of the Guidelines could be used to consider the application of the residual charge to grid-connected batteries. However, the letter does not clearly indicate the Authority's intent, at a policy level, about how the residual charge should apply to grid-connected batteries.[10] As a result there is no clearly expressed intent Transpower can rely on to form a view on whether option 2 or option 3 align with the Authority's intent.
27. In the absence of clear expression of intent by the Authority on the application of the residual charge with respect to batteries, Transpower considers it is not able to propose either option 2 or 3 at this time. Our proposed TPM drafting provided with this submission does not give any special treatment to batteries and, therefore, would effectively implement option 1.
28. In short, we consider the issue of how the residual charge should apply to grid-connected batteries is a policy matter that most appropriately sits with the Authority, as regulator, to resolve.

6 Consistency with the Guidelines

29. Our proposal for application of the residual charge to grid-connected batteries under the new TPM is fully compliant with the Guidelines. We have not proposed to use clause 2 to enable the TPM to differ in its details from the particular requirements in these Guidelines.

[10] Reference document #54 Letter from EA: Batteries and the Residual Charge

TRANSPOWER

Chapter 10: Part F – Adjustments

30 June 2021

Contents: Chapter 10

1 Introduction

1. This chapter summarises and explains our proposals for most of the transmission charge adjustment provisions of the proposed new TPM.
2. This chapter does not include substantive discussion of lagged adjustments to residual charges, reassignment or prudent discounts. Those types of adjustment are discussed in Chapters 8 (Residual charge), 11 (Reassignment) and 13 (Prudent discount policy).
3. Adjustments to transmission charges through the application of the transitional cap are discussed in Chapter 12 (Transitional cap).

2 Requirements of the Guidelines

4. The Guidelines are largely prescriptive as to when benefit-based charges (**BBCs**) and residual charges may, or must, be adjusted.
5. Clauses 25, 26, 31 to 33 and 41 to 44 of the Guidelines contain requirements for adjustments.

> **Upgrading expenditure**
>
> 25. Upgrading expenditure, in relation to existing **benefit-based investments**, means expenditure that results in an extension to the existing **benefit-based investment's** expected **remaining life** or otherwise increases the benefits that **benefit-based investment** is expected to provide.
> 26. The **TPM** must provide that, where Transpower undertakes **upgrading expenditure**, that **upgrading expenditure** must be recovered by either:
>   a. treating the **upgrading expenditure** as a new **benefit-based investment**, in which case the **upgrading expenditure** must be recovered using a method

prescribed in the **TPM** for recovering the **covered cost** of a **post-2019 benefit-based investment** having a capital cost equal to the cost of the **upgrading expenditure**; or

b. treating the **upgrading expenditure** as part of the original **investment** to which the **upgrading expenditure** relates, in which case:

i. the remaining **covered cost** of the overall **benefit-based investment** is to be calculated by combining the **covered cost** of the **upgrading expenditure** with the unrecovered **covered cost** of the original **investment**; and

ii. the allocation of the **benefit-based charge** for the overall **investment** is to be calculated by combining the expected **net private benefits** resulting from the **upgrading expenditure** (determined using the method referred to in clause 26(a)) with the future net private benefits of the original investment, as originally calculated under clause 20 and subject to any adjustments made under clauses 31 to 44.

Changes to annual benefit-based charge parameters

31. 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 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. other costs attributable to the **benefit-based investment**.

Damage to a benefit-based investment

32. The **TPM** must allow Transpower to adjust or end future **annual benefit-based charges** for a **benefit-based investment** where that **benefit-based investment** is destroyed or substantially damaged for reasons that, in Transpower's reasonable opinion, are outside the control of the relevant participants.

Entry, exit, changing use or point of connection

33. The **TPM** must:

a. provide for a process/es for allocating:

(i) **benefit-based charges** and **residual charges** in respect of each new designated transmission customer; and

(ii) **benefit-based charges** in respect of each existing designated transmission customer that increases the use or generation of electricity (where those increases are substantial and Transpower reasonably expects those increases to be sustained) by **large offtake plant** or a **large generating station** at one or more of the customer's points of connection;

b. ensure that the process/es referred to in clause 33(a) result in **benefit-based charges** that, to the extent possible, reflect the share of **net private benefits** that each designated transmission customer is expected to receive from each **benefit-based investment** across the whole of its life (or, for **pre-2019 investments**, its **remaining life** from the date the **benefit-based charge** was first applied to the **investment**);

c. ensure that the process/es referred to in clause 33(a)(i) ultimately result in an annual **residual charge** equivalent to the charge that would, in Transpower's reasonable opinion, have been payable had the **large offtake plant**, **large generating station** or designated transmission customer been fully operational from 1 July 2014;

d. provide that, where a designated transmission customer closes a plant (but remains a designated transmission customer), Transpower will continue to allocate it **annual benefit-based charges** for **investments commissioned** prior to its closure, and these charges should continue until the plant closes or until ten years after the commissioning date of each of the grid **investments** to which the **benefit-based charges** relate (whichever is the later), after which point(s) Transpower must re-allocate those **benefit-based charges** to all remaining designated transmission customers subject to such charges. For the avoidance of doubt, for the purposes of provisions of these **Guidelines** relating to the adjustment of **benefit-based charges**, the closed plant should be treated as though it remains operational until such time as Transpower must re-allocate **benefit-based charges** under this clause;

e. provide that, where a party:

(i) electrically connects or electrically disconnects **large offtake plant** or a **large generating station** to or from the **interconnected grid** through a designated transmission customer (whether that equipment is connected to the designated transmission customer directly or indirectly); or

(ii) increases the use or generation of electricity by **large offtake plant** or a **large generating station** that is electrically connected to the **interconnected grid** through a designated transmission customer (whether that equipment is connected to the designated transmission customer directly or indirectly), where that increase is substantial and Transpower reasonably expects that increase to be sustained,

the **benefit-based charge** and **residual charge** for that designated transmission customer are to be adjusted by the amount that the party would have paid with respect to that equipment had it been separately connected to the grid at the designated transmission customer's point of connection (with consequent adjustments to be made to other designated transmission customers' charges);

f. 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;

g. be designed to minimise any incentive for a participant to inefficiently shift the point of connection of its **large offtake plant** or **large generating station**. The prudent discount policy may apply to circumstances where a designated transmission customer has an inefficient incentive to shift its point of connection, but the remainder of the **TPM** must be designed to minimise such incentives; and

h. provide that, where a designated transmission customer ceases to be a designated transmission customer, Transpower must re-allocate the **benefit-based charges** and **residual charges** which were previously allocated to that designated transmission customer so that these charges are recovered from the remaining designated transmission customers subject to such charges.

Substantial and sustained change in grid use

41. The **TPM** must:

a. provide that Transpower may review the allocation of future **annual benefit-based charges** for a **high-value benefit-based investment** if, in Transpower's reasonable opinion, there has been, or it 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** (which, in Transpower's reasonable opinion, has not been adequately accounted for by applying any of clauses 31 to 40 above as applicable) relative to the time the relevant charges were allocated;

b. provide that a substantial change in grid use will not have occurred:

   (i) for a **post-2019 investment**, where the circumstances which have eventuated were factored into the calculations used to allocate the relevant charges (for example, where scenarios about future developments were used in the allocation); and

   (ii) where there has not been a change in circumstances or event that caused a widespread, substantial change to the pattern of grid use relative to the use at the time the relevant charges were allocated;

c. provide a method or methods for Transpower to determine whether there has been a substantial and sustained change in grid use affecting a **high-value benefit-based investment** (where the methods may differ for different kinds of **investment**); and

d. provide that the method or methods referred to in clause 41(c) are such that the allocation review referred to in clause 41(a) is likely to be only rarely invoked.

Pro-rata adjustments

42. The **TPM** must ensure that where, as a result of an adjustment or adjustments under clauses 31 to 41 or otherwise, the percentage allocators used to allocate the **annual benefit-based charge** in respect of a **benefit-based investment** or the **residual charge** to individual designated transmission customers no longer total 100%, Transpower must adjust those allocators pro-rata so that the allocators total 100%.

The charges may be scaled back

43. The **TPM** must provide for the charges set under it to be scaled back if, in any **pricing year** Transpower wishes to recover less than its **recoverable revenue**.

44. The **TPM** must provide that, where clause 43 applies, Transpower may 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 in the **residual charge**.

3 Stakeholder engagement and process

3.1 Consultation

6. In November 2020, we released a consultation paper seeking feedback on options for BBC allocation methods and methods for adjusting BBCs and residual charges (TPM options consultation paper). The BBC allocation and adjustments components of the new TPM are interrelated, so we consulted on them at the same time.

7. As part of the TPM options consultation process we ran three online drop-in sessions. These were opportunities for stakeholders to ask questions and seek clarification about our thinking in the TPM options consultation paper.

8. The TPM options consultation paper, submissions, cross-submissions, and videos and transcripts of the three online drop-in sessions are available on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[1]

9. We have taken the submissions and cross-submissions into account in preparing the proposed TPM.

3.2 Checkpoint 2

10. In March 2021, we submitted our preliminary proposals for adjustments to the Authority as part of its Checkpoint 2 process.[2]

11. In its feedback on our Checkpoint 2B submission, the Authority commented:[3]

> Regarding Transpower's submission on adjustments, we appreciate the work that Transpower has undertaken in developing its proposals for this complex area of the guidelines and consider that these are progressing well. For the most part, we are broadly comfortable with Transpower's proposals. There remain, however, several areas where Transpower's proposed approach appears to differ from what is required by the guidelines.

12. The Authority asked us to consider and resubmit on a number of substantive issues concerning adjustments to BBCs, set out in Appendix B of its feedback. The Authority's feedback also included some less substantive feedback on adjustments to BBCs and residual charges in Appendix C.

13. We resubmitted our preliminary proposals for adjustments to the Authority in May 2021, responding to the matters the Authority had raised.[4]

14. In its feedback on our Checkpoint 2B resubmission, the Authority commented:[5]

> We welcome the changes to the adjustment sections of the proposed TPM. These now appear in most respects to be consistent with the TPM guidelines and the Authority's intent. However, we have identified some remaining points of feedback, which are discussed at Appendix D.

15. We have taken the Authority's feedback on our Checkpoint 2B submission and resubmission into account in preparing the proposed TPM.

4 Summary of our proposal

16. The proposed TPM deals with adjustments to connection charges, BBCs and residual charges in Part F (clauses 72 to 94).

17. Part F of the proposed TPM delineates adjustment events as connection charge adjustment events, BBC adjustment events and residual charge adjustment events. The table below summarises our proposals for each type of adjustment event, maps them to the

1 TPM Development: Options consultation process
2 Reference document #47 Checkpoint 2B submission: Adjustments.
3 Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph B.68.
4 Reference document #59 Checkpoint 2B resubmission: Adjustments
5 Reference document #67 Letter from EA: Checkpoint 2B resubmission, page 2 and Reference document # 68 Letter from EA: Checkpoint 2B resubmission Appendix A-D. The points in Appendix D related to the whole-of-life approach (discussed in Section 5.6) and step adjustments to residual charges (discussed in Section 6.1).

requirements of the Guidelines, and identifies some proposed departures from the requirements of the Guidelines.

18. The table categorises adjustments as scaling adjustments or reallocation adjustments. A scaling adjustment scales the relevant transmission charge up or down for all customers who pay it. For BBCs, this is achieved by changing the covered cost of the relevant BBI (covered cost is discussed in Chapter 6 (Benefit-based charges (covered cost)). A reallocation adjustment changes customers' allocations of the relevant transmission charge without changing the overall size of it. A reallocation adjustment event affecting a benefit-based investment (**BBI**) may also trigger reassignment of the BBI, which is a type of scaling adjustment (see Chapter 11 (Reassignment)).

19. Our proposals for adjusting connection charges are consistent with current practice and we consider them to be uncontroversial.[6] The rest of this chapter therefore focuses on our proposals for adjustments to BBCs and residual charges.

[6] Our proposals for apportioning connection charges between a vendor and purchaser and for voluntary under-recovery of connection charges (clauses 76 and 77 of the proposed TPM) are consistent with clauses 33(f), 43 and 44 of the Guidelines. The connection charge consequences of customer connection and disconnection are not specifically covered in the Guidelines.

Table 1 Summary of proposals for each type of adjustment event

Adjustment event	Type of adjustment and comments	Proposed TPM clauses	Guidelines clauses	Proposed departure from Guidelines requirements
Connection charge adjustment events				
A customer connects at a connection location where it is not already connected	Reallocation	73(1)(a), 74	11	N/A
A customer disconnects from a connection location	Reallocation	73(1)(b), 75	11	N/A
A customer sells part of its business that constitutes it as a customer at a connection location	Reallocation	73(1)(c), 76	33(f)	N/A
Transpower decides to voluntarily under-recover the connection charge for a connection asset, connection location or connection transmission alternative	Scaling If we decide to voluntarily under-recover a connection charge we must not recover the shortfall through residual charges in any pricing year[7]	73(1)(d), 73(2), 77	43, 44	N/A
Benefit-based charge adjustment events				
There is a change to an input to a BBI's covered cost (other than additional capex)	Scaling	40, 41	31	N/A
There is additional capex on an existing BBI	Scaling or new BBI	38	25, 26	N/A

[7] The wash-up building blocks calculation in Schedule E of the Transpower IPP (Reference document #73) excludes voluntary under-recoveries from the EV account through variable J. This means a voluntary under-recovery will not be recovered through residual revenue in a later regulatory control period when the EV account balance is recovered.

Adjustment event	Type of adjustment and comments	Proposed TPM clauses	Guidelines clauses	Proposed departure from Guidelines requirements
A BBI suffers material damage	Scaling "Material damage" is destruction of, or substantial damage to, the BBI	78(1)(a), 79 Definition of "material damage"	32	N/A
A new customer connects to the grid	Reallocation	78(1)(b), 80	33(a)(i), 33(b), 42	N/A
A customer ceases to be a customer	Reallocation	78(1)(c), 81	33(h), 42	We propose to attribute BBCs for recent BBIs to a related entity of the exiting customer if the related entity is a customer
An existing customer connects plant[8] to the grid (including a large upgrade of grid-connected plant)	Reallocation Grid-connected plant is deemed to be "large". An upgrade is "large" if it increases capacity by at least 10 MW	9, 78(1)(d), 78(3), 82 Definition of "large"	33(a)(ii), 33(b)	N/A
A customer disconnects plant from the grid (including a large de-rating of grid-connected plant)	Reallocation Grid-connected plant is deemed to be "large". A de-rating is "large" if it reduces capacity by at least 10 MW	9, 78(1)(d), 78(3), 82 Definition of "large"	33(d)	We propose to treat a large de-rating of grid-connected plant as closure of grid-connected plant of the same size We propose to attribute BBCs for recent BBIs to a related entity of the plant owner if the related entity is a customer

[8] Based on the definitions of "large generating station" and "large offtake plant" in the Guidelines, the proposed TPM defines "plant" as generating or consuming plant (i.e. not networks).

Adjustment event	Type of adjustment and comments	Proposed TPM clauses	Guidelines clauses	Proposed departure from Guidelines requirements
Large embedded[9] plant is connected to a customer's local network or grid-connected plant (including a large upgrade of embedded plant)	Reallocation Embedded plant is "large" if it has a capacity of at least 10 MW. An upgrade is "large" if it increases capacity by at least 10 MW	9, 78(1)(e), 78(3), 82 Definition of "large"	33(b), 33(e)(i)	N/A
Large embedded plant is disconnected from a customer's local network or grid-connected plant (including a large de-rating of embedded plant)	Reallocation Embedded plant is "large" if it has a capacity of at least 10 MW. A de-rating is "large" if it reduces capacity by at least 10 MW	9, 78(1)(e), 78(3), 82 Definition of "large"	33(d), 33(e)(i)	We propose to treat a large de-rating of embedded plant as disconnection of large embedded plant We propose to attribute BBCs for recent BBIs to a related entity of the plant owner if the related entity is a customer
There is a substantial and sustained increase in grid-connected plant's electricity consumption or generation (without an upgrade)	Reallocation A "substantial sustained increase" is an increase in the plant's expected annual electricity consumption or generation of at least 25% since the current allocations for a BBI were calculated, which is expected to last for at least five years	8, 78(1)(f), 78(4) 83 Definition of "substantial sustained increase"	33(a)(ii), 33(b)	N/A

[9] Under the Guidelines and in the proposed TPM, plant is "embedded" if it is connected, directly or indirectly, to a local network or grid-connected generating or consuming plant.

Adjustment event	Type of adjustment and comments	Proposed TPM clauses	Guidelines clauses	Proposed departure from Guidelines requirements
There is a substantial and sustained increase in large embedded plant's electricity consumption or generation (without an upgrade)	Reallocation A "substantial sustained increase" is an increase in the plant's expected annual electricity consumption or generation of at least 25% since the current allocations for a BBI were calculated, which is expected to last for at least five years	8, 78(1)(g), 78(4), 83 Definition of "substantial sustained increase"	33(b), 33(e)(ii)	N/A
A transformer at a GXP for a distributor's local network is upgraded	Reallocation	78(1)(h), 84	33(a)(ii), 33(b)	We propose to include this as a BBC adjustment event
A distributor connects its local network at a new GXP	Reallocation	78(1)(i), 85	33(a)(ii), 33(b)	We propose to include this as a BBC adjustment event
The point of connection for large plant changes	Reallocation	78(1)(j), 78(6), 86	33(g)	N/A
A customer sells part of its business that constitutes it as a beneficiary of a BBI	Reallocation	78(1)(k), 87	33(f)	N/A
Transpower decides to voluntarily under-recover a BBI's covered cost	Scaling If we decide to voluntarily under-recover a BBI's covered cost we must not recover the shortfall through residual charges in any pricing year	78(1)(l), 78(2), 88	43, 44	N/A

Adjustment event	Type of adjustment and comments	Proposed TPM clauses	Guidelines clauses	Proposed departure from Guidelines requirements
There is a substantial and sustained change in grid use (**SSCGU**)	Reallocation A SSCGU is an event that results in a change in expected total annual grid injection or offtake of at least 5% of average annual injection or offtake of the five most recent complete capacity years, which is expected to last for at least five years	8, 78(1)(m), 78(7), 89 Definition of "substantial sustained change in grid use"	41	N/A
Residual charge adjustment events				
A new load customer connects to the grid	Reallocation	90(1)(a), 91	33(a)(i), 33(c)	N/A
A load customer ceases to be a customer	Reallocation	90(1)(b), 92	33(h)	N/A
A load customer sells part of its business that constitutes it as a load customer	Reallocation	90(1)(c), 93	33(f)	N/A
Transpower decides to voluntarily under-recover residual revenue	Scaling If we decide to voluntarily under-recover residual revenue for a pricing year we must not recover the shortfall through residual charges in any later pricing year	90(1)(d), 90(2)	43	N/A

5 Benefit-based charge adjustments

20. This section discusses key aspects of our proposals for adjusting BBCs, including how our thinking has evolved on some matters.

5.1 Changes in covered cost inputs and material damage

21. Clause 31 of the Guidelines requires the new TPM to include a method for adjusting BBCs when certain inputs to the covered cost of the relevant BBI change.

22. As discussed in Chapter 6 (Benefit-based charges (covered cost)), we propose to calculate a BBI's covered cost annually rather than for the whole life of the BBI when it is commissioned. The annual calculations will reflect changes to the inputs in clause 31 of the Guidelines. We propose to calculate annual covered cost by looking back at the preceding financial year, so there will typically be a delay of one pricing year before the changes to the inputs in clause 31 of the Guidelines come through in BBCs.[10]

23. An exception to this is if there is material damage to a BBI, in which case we propose to immediately reduce the covered cost of the BBI, and re-calculate BBCs, to account for the damage. This "manual" adjustment will be done for the pricing year during which the damage occurred and, potentially, the next pricing year if the reduction in the value of the BBI is not reflected in the BBI's opening RAB value for the preceding financial year (clauses 79(2) and (3) of the proposed TPM).

24. Our preliminary proposal was to define "material damage" by reference to full or partial write offs of assets under GAAP. We reconsidered this proposal in light of the Authority's feedback on our Checkpoint 2B resubmission that this approach may not comply with the Guidelines.[11] We now propose to define "material damage" using the words in clause 32 of the Guidelines, i.e. "destruction of, or substantial damage to, a BBI."

25. Clause 79(4) of the proposed TPM addresses the very unlikely situation contemplated in clause 32 of the Guidelines where a beneficiary of the BBI causes the material damage. In that case, for the purposes of calculating the causing beneficiary's BBC, the covered cost of the BBI is not reduced.

5.2 Further investment in existing BBIs

26. Clauses 25 and 26 of the Guidelines require the new TPM to include a method for adjusting BBCs when there is "upgrading expenditure" on a BBI. Upgrading expenditure is expenditure on an existing BBI that extends its life or increases its benefits.

27. Some types of further investment in an existing BBI will not have a material impact on the distribution of benefits from the BBI. This is most likely to be expenditure driven by a need for maintenance rather than enhancement and development (referred to as "asset replacement" and "asset refurbishment" in Transpower's capital expenditure input

[10] The "look back" approach is a departure from the requirements of clause 17 of the Guidelines. This is discussed in Chapter 6 (Benefit-based charges (covered cost)).

[11] Reference document # 64 Checkpoint 2B resubmission: preliminary TPM drafting.

methodology[12], and as "replacement investment" and "refurbishment investment" in the proposed TPM).

28. Under clause 26 of the Guidelines we have discretion to treat upgrading expenditure as investment in a separate BBI (subclause (a)) or as part of the underlying BBI (subclause (b)). We consider the different treatments would result in a similar overall allocation of BBCs in most cases. However, treating the upgrading expenditure as part of the underlying BBI in accordance with the method in subclause (b) could be analytically difficult in the context of the BBC allocation methods we are proposing to use (at least relative to the separate BBI option).

29. We propose:

    29.1. We will have discretion to treat a refurbishment or replacement investment[13] in respect of a post-2019 BBI as part of the underlying BBI (thereby scaling its covered cost), a separate post-2019 BBI or part of a separate post-2019 BBI in respect of the underlying post-2019 BBI (clause 38(1) of the proposed TPM). In most cases we expect to choose the first option as refurbishment or replacement expenditure is unlikely to have a material impact on the distribution of benefits from the underlying BBI. If we consider the investment will have a material impact on the distribution of benefits from the underlying BBI, clause 38(4) requires us to choose one of the other options.

    29.2. We will have discretion to treat a refurbishment or replacement investment in respect of a pre-2019 BBI in Schedule 1 of the Guidelines/Appendix A of the proposed TPM as a separate post-2019 BBI or part of a separate post-2019 BBI in respect of the underlying pre-2019 BBI (clause 38(2) of the proposed TPM). We will not treat the investment as part of the underlying pre-2019 BBI because doing so would prolong the economic life of the pre-2019 BBI. We consider it would be best to phase out the pre-2019 BBIs as soon as possible so that all BBIs are allocated on a forward-looking basis as post-2019 BBIs.

    29.3. We will treat all "enhancement investments" (being upgrading expenditure[14]) as separate post-2019 BBIs (clause 38(3) of the proposed TPM).[15]

5.3 Intra-regional, inter-regional and pro rata reallocation

30. As outlined in the table above, several clauses of the Guidelines require BBCs to be reallocated if certain defined adjustment events occur.

31. We propose to initially allocate BBCs for post-2019 BBIs using methods that first allocate the net private benefits of the BBI to regions and then allocate each regional net private benefit

---

12 Reference document #71 Transpower Capex IM

13 We note that the definitions of "asset refurbishment" and "asset replacement" in the Capex IM, and of "refurbishment investment" and "replacement investment" in the proposed TPM, are qualitative definitions and are not linked to the financial base capex threshold (currently $20m) under the Capex IM.

14 Refurbishment investment will also be upgrading expenditure because it will increase the life of the underlying BBI. As noted above, if we consider the refurbishment expenditure will have a material impact on the distribution of benefits from the underlying BBI, we will treat it as a separate BBI.

15 This includes the Cromwell-Twizel thermal upgrade and Roxburgh-Livingstone reconductoring components of the LSI Renewables project, which are in progress (the "post-2019 CUWLP investment" in the proposed TPM). Although approved by the Electricity Commission as part of the original project, these components are effectively a separate project, commenced a decade after being approved.

to individual customers within the region using intra-regional (per customer) allocators. This approach is discussed in Chapter 7 (Benefit-based allocation methodology).

32. At the time of our TPM options consultation, our thinking was we would potentially carry out full (inter-regional and intra-regional reallocations) for several different adjustment events. By the time of our Checkpoint 2B submission, our preliminary proposal was that we would only engage in a full reallocation in the case of a substantial sustained change in grid use (SSCGU). The other reallocation adjustment triggers would result in intra-regional reallocations only, although with a fresh calculation of intra-regional allocators in most cases.

33. In its feedback on our Checkpoint 2B submission, the Authority commented:

> B.71 Regarding Transpower's proposal to engage in full recalculations of inter-regional allocations for benefit-based charges only where the substantial and sustained change in grid use (SSCGU) threshold is met, we agree that this is likely to be a practical approach (although noting our comments below on inter- and intra-regional allocations, as well as on pro-rata adjustments and the SSCGU threshold). We also consider that this approach is consistent with our view that benefit-based charge allocations should not generally be reopened save for in very specific circumstances.
>
> B.72 However, we continue to have concerns regarding the range of events which Transpower considers should trigger full intra-regional reallocations, as opposed to a pro-rata adjustment of charges. We consider that the Authority's intent, that once allocations have been made, they should not change except in very specific circumstances, is clear from clause 24 of the guidelines as well as being set out in the Decision Paper from paragraph 9.83 onwards. We have highlighted particular instances where we remain of the view that Transpower's proposals to conduct broader reallocations are inconsistent with the guidelines in the sections below. [16]

34. In response to this feedback, our Checkpoint 2B resubmission modified our preliminary proposals for intra-regional allocations.[17] We proposed to use a pro rata method for new customers, exiting customers and analogous adjustment events.[18] We had understood clause 42 of the Guidelines to be referring to pro rata adjustments to address rounding errors and similar mathematical issues, but the Authority's feedback (paragraph B.84 in particular) made clear the Authority's intent that pro rata reallocation be a fundamental aspect of BBC adjustments.

35. Clauses 80 and 81 of the proposed TPM contain the pro rata method. Those clauses include worked examples to illustrate how the method works for new and exiting customers.

36. Clauses 81(5) to 81(7) of the proposed TPM implement the intent of clause 33(d) of the Guidelines for the situation where the exiting customer has a "related entity"[19] that is also a customer. The exiting customer's BBC for any BBI that is less than 10 years old (a "continuing BBI") moves to the related entity until the pricing year after the pricing year during which the continuing BBI turns 10. This proposal is a departure from clause 33(d) of the Guidelines

[16] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraphs B71 and B72

[17] Reference document #59 Checkpoint 2B resubmission: Adjustments, section 2.

[18] We propose to treat large plant changes and substantial and sustained increases in consumption or generation by large plant as analogous to the entry or exit of a customer, as appropriate. See paragraph 45.

[19] A "related entity" of a person is "another person that controls, is controlled by, or is under common control with the first person", and includes related companies.

because that clause requires the exiting customer itself to remain a customer, which clearly it will not. This is discussed in Section 8.1.

37. The pro rata method needs to work differently for the pre-2019 BBIs than it does for post-2019 BBIs because the allocations for the pre-2019 BBIs calculated by the Authority are not regionalised. For reallocating the BBCs for the pre-2019 BBIs when a new customer enters, we propose to use a method based on the incumbent customers' "benefit factors" (% per MWh)[20] (clauses 4 and 80(6) of the proposed TPM). This is consistent with our thinking in our TPM options consultation paper and our preliminary proposals in our Checkpoint 2B submission and resubmission.

38. When a SSCGU occurs, we propose to recalculate the BBC allocations for affected high-value post-2019 BBIs using a standard method (noting the SSCGU adjustment event only applies to high-value BBIs) (clause 89 of the proposed TPM). This will result in new inter-regional and intra-regional allocations for the affected BBIs, i.e. a full reallocation. In both our Checkpoint 2B submission and resubmission, our preliminary proposal was not to apply this method of reallocation to any high-value pre-2019 BBI[21] affected by a SSCGU. This remains our proposal because the allocations for the pre-2019 BBIs are backwards-looking and not regionalised, and are therefore not compatible with a forward-looking, inter-regional reallocation. We do not consider this to be a departure from the requirements of the Guidelines.[22]

    38.1. As discussed below, a SSCGU will always be the entry or exit of a very large customer or an analogous event. This will trigger a (large) pro rata reallocation of BBCs for the pre-2019 BBIs. There will be a reallocation adjustment for the pre-2019 BBIs in response to the SSCGU, just not one that uses the method applying to post-2019 BBIs.

    38.2. In any event, clause 41(a) of the Guidelines uses the word "may", not "must", which provides flexibility in terms of how the SSCGU adjustment trigger is applied in the new TPM, including the types of high-value BBI it is applied to.

39. Our proposed definition of SSCGU is an event or series of directly related events that results in a change in expected total annual grid injection or offtake of at least 5% of average annual injection or offtake over the five most recent complete capacity years,[23] and that is sustained. "Sustained", in the definition of SSCGU, and throughout the proposed TPM, means expected to last for at least five years (clause 8 of the proposed TPM). We consider the five-year period strikes an appropriate balance between material longevity and our ability to make reasonably accurate forecasts.

40. We developed this definition of SSCGU in response to the Authority's feedback on our Checkpoint 2B submission that our, then qualitative, proposed definition of SSCGU *"would be insufficient to satisfy the requirement in the guidelines for Transpower to provide a method for*

[20] We propose the benefit factors would be based on historic calculated or estimated injection or offtake, so there would be no scope for customers to manipulate them.

[21] It is possible not all of the pre-2019 BBIs will be high-value, and possibly none of them will be, by the time a SSCGU occurs (if one ever does).

[22] Reference document #56 Letter from EA Checkpoint 2B submission. At paragraph B.94 the Authority suggested our proposal was not consistent with clause 41 of the Guidelines because that clause *"clearly contemplates adjustments for more than just post-2019 investments"*.

[23] A "capacity year" is a 12-month period from 1 September to 31 August. This aligns with the "capacity measurement period" under the current TPM.

determining whether there has been substantial change."[24] A feature of the proposed definition is that the change in injection or offtake must be attributable to a single event or series of directly related events. Accordingly, "creeping" SSCGUs are not possible. By this definition, SSCGUs will be very rare, as required by clause 41(d) of the Guidelines. They will also be of such magnitude that, in our view, they will not be adequately accounted for by a pro rata reallocation of the BBCs for the affected high-value post-2019 BBIs.

41. Our proposed definition means a SSCGU will always be the entry or exit of a very large customer or an analogous event.[25] This will constitute one of the other BBC adjustment events as well as being a SSCGU. We propose to carry out the appropriate (pro rata) intra-regional reallocation before the full reallocation for the SSCGU takes effect (clause 78(7) of the proposed TPM). We propose to implement the full reallocation at the start of a pricing year (see Section 7).

42. For some post-2019 BBIs ("peak BBIs") we propose to use a mean historical coincident peak offtake intra-regional allocator (clause 63(1) of the proposed TPM). We acknowledge this theoretically introduces the possibility of customers managing their peak demand in anticipation of a SSCGU applying to those BBIs. However, in practice, given SSCGUs will be rare, we think this incentive will be weak and unpredictable, and it is unlikely customers will change their behaviour.[26]

5.4 Large plant changes and increases in consumption or generation

43. Clauses 33(a)(ii) and 33(e) of the Guidelines require the new TPM to include methods for reallocating BBCs when there are:

    43.1. large plant changes, whether grid-connected or embedded; or

    43.2. substantial and sustained increases[27] in generation or consumption by existing large plant, whether grid-connected or embedded.

44. We propose:

    44.1. Any plant connected directly to the grid would be deemed to be large, as required by the Guidelines[28] (proposed definition of "large").

    44.2. Embedded plant would need to have a capacity of at least 10 MW to be considered large (proposed definition of "large"). We consider this to be an appropriate threshold for embedded plant because it aligns with the thresholds for generator offers in clauses 8.25(5) and 13.25(1) of the Code and there are few current examples of grid-connected plant less than 10 MW.

    44.3. A large upgrade of existing plant would be treated the same as the connection of new large plant. Similarly, a large de-rating of existing plant would be treated the same as

---

24 Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph B93.

25 We consider very substantial changes to the grid itself will be adequately addressed through a combination of charging for new BBIs and, potentially, reassignment.

26 We consider any allocation metric that attempts to allocate charges in proportion to net private benefits will suffer this problem. There is no perfect metric that is both accurate and completely removes incentives for customers to act in ways that may avoid charges if there is a SSCGU.

27 This is not the same as a SSCGU, which has a much higher threshold. We note that substantial and sustained reductions in generation or consumption are not adjustment events in the Guidelines.

28 Definitions of "large generating station" and "large offtake plant" in the Guidelines.

the disconnection of large plant. Incremental upgrades and de-ratings could accumulate to become large. See clause 78(3) of the proposed TPM and the proposed definitions of "large", "upgrade" and "de-rating".

44.4. We would have discretion to combine separate units of plant to make the "large plant" assessment if we consider it appropriate to do so, including to counteract avoidance behaviour (clause 9 of the proposed TPM).

44.5. A substantial sustained increase would occur if there is an increase in large plant's expected annual electricity consumption or generation of at least 25% since the current allocations for a BBI were calculated,[29] and the increase is sustained, i.e. expected to last for at least five years (clause 8 of the proposed TPM and proposed definition of "substantial sustained increase").

45. We propose to treat large plant changes and substantial sustained increases as analogous to the entry or exit of a customer (as appropriate). Clauses 82 to 85 of the proposed TPM do this by referring back to the new and exiting customer provisions in clauses 80 and 81 and imagining a separate notional customer entering or exiting at the relevant connection location. The notional new or exiting customer's allocation is then attributed to the relevant customer.

46. There is an exception to this mechanism when large plant changes its point of connection (clause 86 of the proposed TPM, which implements clause 33(g) of the Guidelines). The effect of clause 86(4) of the proposed TPM is that a large plant owner cannot access a lower allocation for a BBI by moving the large plant's point of connection. The large plant owner, or its host customer, always takes the higher allocation.

47. Clauses 82(5) to 82(7) of the proposed TPM implement the intent of clause 33(d) of the Guidelines for the situation where the large plant owner remains a customer after the disconnection of the large plant or has a "related entity" that is a customer. See paragraph 36 and the discussion in Section 8.1.

48. In our Checkpoint 2B submission we noted that clause 33(a)(ii) of the Guidelines does not expressly capture the connection of new plant to the grid or the upgrade of existing grid-connected plant.[30] In its feedback[31] on our Checkpoint 2B submission, the Authority interpreted clause 33(a)(ii) as capturing both new and upgraded plant. We agree with that interpretation and have adopted it for our proposals.

49. In contrast, the Authority interpreted clause 33(d) of the Guidelines, which relates to "closing" grid-connected plant, as not capturing the de-rating of existing grid-connected plant.[32] We have assumed that interpretation is correct. Accordingly, our proposal to reallocate BBCs when there is a large de-rating of grid-connected or embedded plant is a departure from the requirements of clause 33(d) of the Guidelines. This is discussed in Section 8.2.

---

[29] The substantial increase threshold needs to be BBI-specific because it is possible the value of a beneficiary's intra-regional allocator for a BBI, if the value was estimated, already factors in the increase in generation or consumption or part of it.

[30] Reference document #47 Checkpoint 2B submission, paragraph 75 and 78.

[31] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph C.25 and C.26.

[32] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph B.82.

50. In response to our TPM options consultation paper, Creative Energy Consulting (for Trustpower)[33] submitted it is anomalous for a distributor to potentially pay higher BBCs if a large embedded generator connects to the distributor's local network, because in that case the distributor will be using the grid, and benefitting from it, less (and vice versa if a large embedded generator disconnects). We agree that, on the face of it, this result is counter-intuitive. However, it is required by clause 33(e) of the Guidelines and reflects the Authority's policy behind its reform of transmission pricing.[34]

5.5 Local network changes

51. The clauses of the Guidelines dealing with large plant changes do not apply to local networks because local networks do not fall within the definition of "large generating station" or "large offtake plant" in the Guidelines.

52. In our TPM options consultation paper, our preliminary proposal was to extend the substantial sustained increase adjustment event to cover transformer capacity upgrades at a GXP for a distributor's local network. We considered this proposal appropriate to capture local network load increases attributable to the combined impact of residential and commercial development on the network, i.e. not attributable to large plant in the network.

53. There was unanimous support for this proposal from submitters on our TPM options consultation paper who commented on it. We included the proposal in our Checkpoint 2B submission, and the Authority commented in its feedback:

> We also agree that Transpower's proposal to depart from the guidelines and include distributors' upgrades to transformers at a GXP as a substantial and sustained increase in load may be justifiable under clause 2 and the Authority will consider Transpower's proposals in this regard as part of considering the proposed TPM. [35]

54. Clauses 78(1)(h), 78(1)(i), 84 and 85 of the proposed TPM implement this proposal, which we have extended to include a distributor connecting its local network at a new GXP. There would be no adjustment in the new GXP situation if Transpower determines the connection is not associated with an expected increase in the distributor's total offtake in the relevant region, or the expected increase is already factored into the value of the distributor's intra-regional allocator for the relevant regional demand group (clause 85(3) of the proposed TPM).

55. This proposal is a departure from the requirements of clause 33(a)(ii) of the Guidelines (by way of extension). This is discussed in Section 8.3.

5.6 Clause 33(b) of the Guidelines - whole-of-life approach

56. Clause 33(b) of the Guidelines requires the methods for attributing BBCs to new customers and to existing customers for large plant changes and substantial sustained increases to *"reflect the share of net private benefits that each [customer] is expected to receive from each benefit-based investment across the whole of its life [or remaining life]"*, but only *"to the extent*

[33] Creative Energy Consulting report (pages 17 and 18) for Trustpower submission to BBC Options consultation

[34] For example, Reference document #3 2020 Decision, page ii under "Removing opportunities to avoid charges and barriers to investment".

[35] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph C.27.

possible". In our TPM options consultation paper we referred to this as the total benefits approach. It has since become known as the whole-of-life approach.

57. The Authority's approach to the whole-of-life assessment, as envisaged in its feedback on our Checkpoint 2B submission and in other examples, involves what is effectively a backward-looking adjustment. Under the Authority's proposed approach, a new customer's BBC allocations would depend not only on its forward-looking expected net private benefits from the relevant BBI, but on the net private benefits incumbent customers were expected to receive from the BBI in the past, as assessed at the time the BBI was commissioned, and the BBI's past covered cost profile.

58. At the time of our TPM options consultation, our thinking was we would propose a backward-looking adjustment to give effect to the whole-of-life approach. This proposal was opposed by all submitters who commented on it.[36] Those submitters considered BBC allocations should be based on expected net private benefits on a forward-looking basis only.

59. After considering that stakeholder feedback and the practicability of a backward-looking adjustment, our preliminary proposal in our Checkpoint 2B submission and resubmission was not to include this mechanism in the new TPM as a way of implementing clause 33(b) of the Guidelines. Having considered the Authority's further feedback, this remains our proposal.

60. In our Checkpoint 2B resubmission we said:

> 21. In order for the whole-of-life approach to achieve real alignment between beneficiaries' lifetime positive net private benefits from, and their lifetime contributions to the covered cost of, a BBI, it must be assumed that the existing beneficiaries' prevailing estimates of positive net private benefits from the BBI accurately reflect their actual positive net private benefits over the BBI's life.
>
> 22 In a world of perfect certainty, we agree the combination of the pro-rata method and the whole-of-life approach would, on average, be consistent with the intent of the Guidelines. However, in reality, the new customer's expected benefits may be substantially different than the benefits we calculated for an identical existing customer when the BBI was originally commissioned. For example:
>
> 22.1. The existing customers' use of the grid may have changed, which will affect the benefits of a new customer. For example, if the existing customers are using the grid to a greater extent than originally predicted, the new customer's expected net private benefits will be greater because there would be less spare capacity in the grid without the investment. This is a key feature of networks – an individual customer's benefits cannot be calculated in isolation of the benefits to other customers.
>
> 22.2. Our expectations of other factors affecting net private benefits (e.g. fuel costs) may have changed since the original assessment.
>
> 23. In other words, if we were to calculate the new customer's expected net private benefits using new information we have at the time they connect, but apply the pro-rata method to existing customers (which implicitly uses the original assumptions used to calculate their net private benefits), two identical customers would have different annual expected net private benefits from the time the new customer connected, which would be clearly

[36] Reference document #53 TPM Options consultation: Summary and Response, page 22

incorrect. The whole-of-life approach would then exacerbate the problem by using these incorrect values to rebalance charges between new and existing customers from the time the new customer connects.

24. For these reasons, it is not possible in our view to achieve real alignment between beneficiaries' lifetime positive net private benefits from, and their lifetime contributions to the covered cost of, a BBI, when a new customer enters. Clause 33(b) of the Guidelines only needs to be implemented in the TPM "to the extent possible". We do not consider it is possible to implement clause 33(b) in a way that achieves the Authority's intent in clause 11.37 of the Authority's Guidelines decision paper. It is certainly not reasonably practicable to do so, having regard to clause 1(b) of the Guidelines. [37]

61. The Authority had provided a worked example of the whole-of-life approach in footnote 28 of its feedback on our Checkpoint 2B submission.[38] We noted in our Checkpoint 2B resubmission that:

> The whole-of-life approach would be significantly more complex and contentious than the Authority's example in footnote 28 (which appears to contain some errors) suggests. Among other simplifying assumptions in footnote 28, the Authority has assumed no operating costs, a discount rate of zero, and "no uncertainty". None of that will be true in reality. In reality, we will have to make a number of assumptions about the future (potentially out to several decades), including as to the future covered cost of the BBI, the future existence of beneficiaries and other future allocation adjustment events. Those assumptions, like all forecasts, will inevitably be wrong, regardless of whether they probability-weight the future or grossly over-simplify it (as the Authority's example does). [39]

62. In its feedback on our Checkpoint 2B resubmission the Authority said this about the problems with matching lifetime benefits to lifetime charges (emphasis added):

> D.9 Second, Transpower suggests that because of uncertainty when setting initial estimates of benefits, by the time a new entrant enters, the charges of incumbents will no longer represent their forward-looking expected private benefits. We agree. Accordingly, Transpower argues that, if the charges for the new entrant are set on the basis of its expected benefits over the life of the investment compared to the lifetime benefits of the incumbents collectively, there will be a disconnect between the charges paid by the new entrant and the concurrent charges paid by the incumbents and the forward-looking benefits. We agree. There will also be a disconnect between the various incumbents' charges and the benefits they would be assessed as having at the time the new entrant enters; that is, two incumbents that were assessed as having the same benefits and so face the same charges will almost inevitably end up paying the same charges yet getting different benefits. <u>These disconnects are an inevitable consequence of the Authority's intent that the charges be fixed-like, and the consequent decision to adjust the incumbents' charges pro-rata to take account of the charges being paid by the new entrant.</u> We do not consider that is a sufficient reason to move away from the beneficiaries-pay principle for the new entrant relative to the incumbents collectively. Adopting the lifetime benefits approach ensures that the new entrant's charges are expected to be commensurate with the average charges paid by incumbents collectively

37 Reference document #59 Checkpoint 2B resubmission: Adjustments
38 Reference document #56 Letter from EA: Checkpoint 2B submission, page 20.
39 Reference document #59 Checkpoint 2B resubmission: Adjustments, footnote 3.

over time (since then the new entrant's charges are set by reference to the estimated of its share of the estimated total lifetime benefits from the investment). [40]

63. We continue to have serious concerns with the Authority's approach to these issues of competition and discrimination. We think the Authority is under-estimating the significance of an outcome where customers with the same forward-looking benefits profile are charged different amounts, or an outcome where a potential new entrant knows it will pay more than its competitors should it decide to enter. The Authority's response, that the new entrant would be willing to trade these very real and present damages to competition in the market in return for an intangible and theoretical equating of customer positions across decades, is not convincing.

64. Nor is the Authority's explanation of the problem to be solved by a backward-looking adjustment convincing. The Authority's view is that, without such a mechanism, *"the effect [of the new TPM] would be to encourage a new entrant to enter later to avoid its share of the charges"*.[41] Given the long life of most transmission investments and the high likelihood they will be upgraded or refurbished several times during their life, we do not consider this incentive would be strong, if it existed at all. As the responses to our TPM options consultation show, stakeholders expect predictable, forward-looking price signals to inform decision-making, not the unpredictability of a mechanism that responds to past events.

65. It is because we have these serious concerns with the market impact of backward-looking adjustment that we highlighted these issues in our Checkpoint 2B submission and resubmission.

66. We also have serious concerns about whether a backward-looking adjustment could achieve the result contemplated in clause 33(b) of the Guidelines (matching lifetime benefits to lifetime charges) in anything approaching a robust way. The mechanism does not adequately account for the range of real world factors relevant to the assessment of lifetime benefits and lifetime costs. The transmission assets in question have lives of several decades, in a market that has and will continue to experience significant change. The uncertainties in estimating benefits and costs over that time frame, in that context, are significant.

67. Some of these uncertainties are mentioned above. As the Authority has acknowledged, the benefits received by the incumbent beneficiaries of a BBI (in the past and the future) will inevitably be different to those we assessed when the BBI was commissioned. This will also inevitably be the case for the new customer's actual and assessed future benefits from the BBI. There will be the likelihood, but uncertain timing and magnitude, of future investment in the BBI, changing both the covered cost of the BBI and potentially the benefits received from it. There is also the possibility of further new customers entering (itself potentially triggering new costs), customers exiting, large plant changes, and so on. All of these uncertainties and effects over the decades-long life of the BBI would need to be discounted back to the first year of the BBI, at an appropriate discount rate each time.

68. The principle in clause 1(b) of the Guidelines, which requires Transpower to balance the merits of precision with important practical considerations of robustness, simplicity, certainty, and administrative cost, is very relevant in this context. In our view, a backward-looking

40 Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A-D

41 Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A-D, paragraph D.7.

adjustment would result in only false precision while adding significantly to the administrative burden of the new TPM.

69. We consider a backward-looking adjustment will not increase our levels of confidence that BBCs reflect the share of net private benefits each customer is expected to receive from a BBI across the whole of its life. For this reason, the proposed TPM reflects a forward–looking approach to reallocating BBCs when a new customer enters (clause 80 of the proposed TPM). We have concluded the proposed TPM complies with clause 33(b) of the Guidelines, to the extent it is possible to do so, without including a backward-looking adjustment.

6 Residual charge adjustments

70. This section discusses a key aspect of our proposals for adjusting residual charges, namely how to deal with changes to large consuming plant that do not involve a new or exiting load customer, including how our thinking has evolved.

71. This chapter and section are concerned with the extent to which the new TPM should provide for step adjustments to residual charges. As noted above, the lagged adjustment mechanism for residual charges is discussed in Chapter 8 (Residual charge) of this paper. In short, that mechanism involves adjusting the allocation of residual charges according to changes in load customers' average annual total gross energy over an historic five-year period.

72. Chapter 8 (Residual charge) also discusses our proposals for calculating residual charges for new load customers.[42]

6.1 Changes to large consuming plant

73. At the time of our TPM options consultation, our thinking was the new TPM should provide for residual charges to be adjusted (reallocated) whenever there is a change to large consuming plant,[43] whether grid-connected or embedded. We noted that, while clause 33(a)(ii) of the Guidelines does not provide for residual charges to be reallocated when there are changes to grid-connected plant, clause 33(e)(i) does appear to require this when there are changes to large embedded plant, and it would be odd if there were a different outcome depending only on where large plant is connected.

74. We referred to this preliminary proposal in our early Checkpoint 2 submission for residual charges and the transitional price cap (or Checkpoint 2A submission).[44] In its feedback on our Checkpoint 2A submission, the Authority commented:

> A.11 Transpower is proposing that the residual charge would immediately change when a large customer plant is connected to or disconnected from the grid by an existing customer or when there is a large upgrade or derating of existing grid-connected consumer plant.

[42] Only load customers pay residual charges. In Chapter 8 (Residual charge) of this paper we discuss how "load customer" is defined in the proposed TPM, which involves a departure from the requirements of the Guidelines.

[43] Changes to large generating plant should not impact on the allocation of residual charges because the allocator is a gross load metric.

[44] Reference document #31 Checkpoint 2 submission: Residual Charge and Transitional Cap.

A.12 In our view this proposal does not reflect the correct interpretation of the guidelines, which provide that such a change would occur gradually, after a lag. The guidelines provide for regular updates to the allocation of the residual charge based on lagged changes in usage. The initial allocation of the residual charge (which is based on historical gross AMD) is to be adjusted annually based on changes in the four-year rolling average of gross annual energy usage, with a lag.

A.13 Clause 33(e), which deals with the connection, disconnection or increase in use/generation by embedded plant, provides that where this occurs the transmission customer's residual charge is to be adjusted by the amount that the party would have paid if the plant had been separately connected to the grid. If a transmission customer opened or closed a plant, or changed its use of electricity, those changes would be accommodated after the lag in the residual charge (by the ordinary operation of the residual charge clauses or because of the absence of a reference to the residual charge in clause 33(a)(ii)). We consider the guidelines require the same approach for embedded plant.[45]

75. In our Checkpoint 2A resubmission[46] we expressed our reservations with this approach because of its potential to produce arbitrary results. For example, at paragraph 13.1 we observed *"an existing [customer] connecting new load to the grid would not immediately incur an increased residual charge, whereas a new [customer] connecting the same load would."*

76. We persisted with our preliminary proposal in our Checkpoint 2B submission and resubmission. In our Checkpoint 2B submission we acknowledged our preliminary proposal would likely be a departure from the requirements of clause 33(a)(ii) of the Guidelines, and said:

27. We consider the TPM should not result in materially different (discriminatory) outcomes, in terms of the timing of impacts on the RC [residual charge] allocation, depending only on:

27.1 whether consuming plant is connected to the grid by a new or existing load customer;

27.2 whether the disconnection of consuming plant from the grid results in the load customer ceasing to be a customer; or

27.3 whether grid-connected consuming plant is upgraded rather than connected, or de-rated rather than disconnected.

28. We consider these arbitrary differences should not affect adjustments to the RC allocation because they have the potential to:

28.1 incentivise inefficient investment and/or corporate structuring decisions by load customers, aimed only at delaying impacts on RC allocation; and

28.2 adversely affect competitive neutrality between load customers.

29. We consider a TPM that enshrines these arbitrary differences, or others such as different outcomes depending on whether something happens on the grid interface or a local network, would be inconsistent with the efficiency and competition limbs of the Authority's statutory objective.

[45] Reference document #35 Letter from EA: Checkpoint 2A submission.
[46] Reference document #44 Checkpoint 2 resubmission: Residual Charge and Transitional Cap

30. Accordingly, our proposal is to depart from the requirements of clause 33(a)(ii) by providing for an RC step adjustment in all situations where an existing load customer:

    30.1 connects or disconnects consuming plant to or from the grid; or

    30.2 upgrades or de-rates grid-connected consuming plant if the upgrade or de-rating is large.

31. There was near unanimous support for this proposal from submitters [on our TPM options consultation paper] who commented on it

32. We consider this departure is consistent with the Intent of the Guidelines:

    32.1 Clause (v) of the Guidelines says the purpose of the RC is to recover residual revenue "in a way which is designed to minimise any effect on designated transmission customers' decision-making."

    32.2 More generally, the Authority's decision to replace the current interconnection and HVDC charges with the benefit-based and residual charges is predicated on removing incentives for inefficient investment. The Authority said this in its 2019 issues paper:

    > These new charges would replace the current RCPD and HVDC charges. They are purposely designed to be independent of grid use and so hard to avoid. This would mirror Transpower's own cost structures which are largely fixed and not dependent on grid use.
    >
    > The proposed charges would therefore minimise inefficient grid use and inefficient investments. These new charges would send better signals to consumers about the economic cost of using the grid, without distorting grid use or investment in grid-connected generation and transmission alternatives.

33. If the TPM provides for a step adjustment to the RC allocation when an existing load customer connects/upgrades or disconnects/de-rates grid-connected consuming plant, it should also apply that rule to embedded connections, disconnections, upgrades and de-ratings under clause 33(e)(i) of the Guidelines. Otherwise, another arbitrary timing difference would be introduced based on whether consuming plant is grid-connected or embedded.

77. The Authority responded in its feedback on our Checkpoint 2B resubmission:

    D.14 We agree with the general sentiment that arbitrary differences should not cause difference in how charges are adjusted, other things equal. However, what the argument in the quotation above neglects is that there is a boundary issue that creates an arbitrary distinction that cannot be avoided. That boundary is that in general the charges are fixed-like, but if a customer exits, its charges must reduce to zero. This then raises the question about what happens if a customer partially exits. For example, if a customer reduces its production and energy use by 90%, is it more efficient that its charges remain fixed-like or that they vary? If they are fixed-like it strengthens the incentive for inefficient exit (because the customer can reduce its transmission charges by 100% by reducing production a further 10%). If they vary, it creates an inefficient incentive to reduce use (because that reduces charges without reducing transmission costs).

    D.15 The decision reflected in the Guidelines is:

    [a] to keep the charges fixed-like when the change in use is not substantial and sustained

[b] to change the charges immediately when there is exit and entry

[c] to partially change the charges (by changing the benefit-based charge immediately but to change the residual charge only with a lag) when the change is substantial and sustained but does not involve complete exit or new entry.

D.16 Clause 33(e) of the Guidelines then mandates a parallel treatment in respect of embedded parties. If Transpower remains concerned about the difference in treatment between a new customer and an existing customer that increases its use or generation, it could potentially consider instead adopting a treatment parallel to clause 33(a)(ii) for new customers. That is, under such an approach the new customer would face the benefit-based charge immediately, but it would only be subject to a residual charge after a lag. While we consider that this would require using clause 2 to justify the departure from the guidelines, we consider that is likely to be less problematic than the treatment currently provided for in the draft proposed TPM.

[Footnote 37] For the avoidance of doubt, we consider that an embedded party that has large plant indirectly connected to the grid and completely disconnects (so it has no large plant directly or indirectly connected to the grid) would be treated in a manner parallel to an exiting customer, and a party who disconnected some large plant but continued to have other large plant directly or indirectly connected to the grid would be treated in a manner parallel to a continuing customer. [47]

78. Paragraphs D.14 to D.16 of the Authority's feedback on our Checkpoint 2B resubmission are a clear statement of the Authority's intent, in view of which we are unable to rely on clause 2 of the Guidelines to go forward with our preliminary proposal. Accordingly, the proposed TPM does not include step adjustments to residual charges for changes to large consuming plant.

79. However, we do not agree with the Authority's interpretation of clause 33(e) in footnote 37 of its Checkpoint 2B resubmission feedback, and do not propose to implement it. As we said in our Checkpoint 2B submission (in the context of BBCs):

> 86. We do not interpret clause 33(e)(i) as meaning BBCs should only be adjusted if a disconnection of large embedded plant would have resulted in the owner of the plant ceasing to be a designated transmission customer had the plant been connected directly to the grid, i.e. that clause 33(a)(i) is relevant to the interpretation of clause 33(e)(i). That would mean BBCs would not be adjusted if the embedded party happened to also be a Transpower customer but would be adjusted if the embedded party happened to not be a Transpower customer. We consider that would be an entirely arbitrary interpretation and application of clause 33(e)(i) and should not be preferred over a relatively straight-forward reading of the clause. We do not consider our interpretation to be a departure from the requirements of clause 33(e)(i) of the Guidelines. [48]

80. The same reasoning applies to any adjustment that depends on the entirely arbitrary factor of whether a large embedded plant owner happens to own other embedded plant.

[47] Reference document #68 Letter from EA: Checkpoint 2B resubmission Appendix A-D.

[48] Reference document #47 Checkpoint 2B submission: Adjustments, paragraph 86.

7 Implementation of adjustments

81. The Guidelines are not prescriptive about when and how adjustments to transmission charges under the new TPM are to be implemented, i.e. when and how the adjustments will take effect in transmission charges.

82. Clause 72 of the proposed TPM contains some general rules for making adjustments:

    82.1. We may not know an adjustment event has occurred, especially those affecting embedded plant. An adjustment event is deemed to have occurred on the date we find out about it.

    82.2. Subject to some exceptions discussed below, transmission charges must be adjusted from the date of the adjustment event.

    82.3. The order in which we process adjustments may make a difference to transmission charges. We will process adjustments in the order the adjustment events happen, and may determine an order in, what we consider will be, the rare case of simultaneous adjustment events.

83. Where possible, we adjust transmission charges at the start of a pricing year. This is because our customers need to know what their transmission charges will be for the full pricing year so they can make their own pricing decisions. We do sometimes wash-up transmission charges at the end of a pricing year to correct over-recoveries, but we rarely increase a customer's transmission charges during a pricing year.

84. Consistent with this practice, we propose:

    84.1. A new customer's transmission charges will start as soon as reasonably practicable (we need some time to calculate the charges and get them reviewed). The charges will be back-dated to the date the new customer entered. These measures will eliminate any incentive a new customer may have to avoid transmission charges by timing its entry for early in a pricing year. This will also apply to adjustment events analogous to the entry of a new customer and material damage to a BBI.

    84.2. When we start transmission charges for a new customer (or an analogous adjustment event) we may over-recover charges for a pricing year if other customers' charges are not immediately adjusted. In this case, we will rebate the over-recovery to the other customers at the end of the pricing year or as soon as reasonably practicable after that.

    84.3. An exiting customer's transmission charges will stop immediately. This will also apply to adjustment events analogous to an exiting customer.

    84.4. When we stop transmission charges for an exiting customer (or an analogous adjustment event) we will under-recover charges for at least one pricing year. We will not increase other customers' charges during a pricing year to correct the under-recovery because those customers may face recoverability difficulties if we increase their transmission charges above the levels we indicated at the start of the pricing year. Instead, we propose to carry the under-recovery into our EV account and recover it (netted with any other under-recoveries and over-recoveries) over the course of the next regulatory control period, as contemplated in the Transpower input methodologies.[49]

85. For other types of adjustment (SSCGUs and also reassignment and prudent discounts) we propose to implement the adjustment from the start of the first pricing year that starts at least six months after the adjustment is confirmed (or an earlier pricing year if we determine it is practicable to do so). This will allow us to factor the adjustment into our normal annual pricing process.[50]

86. The following table summarises our proposals for implementing adjustments:

Table 2 Proposals for implementing adjustments

Approach	Adjustment event	Proposed TPM clauses (in addition to clause 72
Paragraphs 84.1 and 84.2 (new customer or analogous adjustment event; material damage)	New customer, new load customer, connecting customer, increasing customer, upgrading customer	74(4) and (5) 80(8) and (9), 91(3) and (4)
	Partial sale of business	76(4) and (5) 88(3) and (4) 94(3) and (4)
	Voluntary under-recovery	77(4), 88(4) and 94(4)
	Material damage to a BBI	79(5)
Paragraphs 84.3 and 84.4 (exiting customer or analogous adjustment event)	Exiting customer, exiting load customer, disconnecting customer	75(2), 81(3), 92(2)
Start of first pricing year starting at least six months later (proposed definition of "start pricing year")	SSCGU	89(4)
	Reassignment	95
	Prudent discount	119(3)

87. As noted above, we propose most scaling adjustments to BBCs would take effect through the annual calculation of covered cost This includes adjustments as further assets and transmission alternatives are commissioned during the life of a BBI.

88. We propose to consult on material adjustments to transmission charges, as required by clause 5(f) of the Guidelines (clause 17 of the proposed TPM). For covered cost adjustments, the consultation would be limited to any material adjustment to the expected total covered cost. We do not propose to consult on covered cost adjustments that occur through the routine annual recalculations.

49 Reference document #72 Transpower IMs

50 Under clause 41.5(a) of the benchmark transmission agreement, we must give at least three months' notice of a change to transmission charges that will be effective at the start of a pricing year. Before we notify customers, the new transmission charges need to be calculated, audited and approved by our Board.

8 Consistency with the Guidelines

89. Except for the proposed departures discussed below, we consider our proposals for adjustments are fully compliant with the Guidelines.

8.1 Attribution of BBCs for recent BBIs to related entities

90. In our Checkpoint 2B submission we noted that corporate structuring could be used to avoid the 10-year rule in clause 33(d) of the Guidelines. In paragraph C.28 of its feedback on our Checkpoint 2B submission the Authority agreed *"that some provision will likely be necessary to deal with corporate structures that have the effect of undermining the intent of the guidelines, whether that is as a result of deliberate avoidance behaviour or because of some other genuine corporate purpose."*

91. As noted above, we propose to depart from the requirements of clause 33(d) of the Guidelines by applying the 10-year rule in situations where a "related entity" of the exiting or disconnecting customer remains a customer.

92. We consider this departure is justified under clause 2 of the Guidelines.

    92.1. We consider the departure is not inconsistent with the intent of the Guidelines. In its 2019 issues paper supplementary consultation, the Authority described the intent of the 10-year rule as follows:[51]

    > This was intended both to ensure the customer properly scrutinises grid investment proposals during the investment approval process and to avoid creating an inefficient incentive to shut down a plant in order to avoid the benefit-based charge.

    It is consistent with this intent to remove a way in which the operation of the 10-year rule could be easily avoided, e.g. by a customer transferring assets to a sister company shortly before exiting or disconnecting.

    92.2. We consider the departure promotes the efficiency limb of the Authority's statutory objective. The 10-year rule is in the Guidelines so as not to *"weaken the customer's incentive to reveal relevant information during the investment approval process [which] would be inefficient where long-term grid investments are made in the wrong expectation of long-term demand from a customer."*[52] Removing a way in which the operation of the 10-year rule could be easily avoided helps avoid this potential inefficiency.

93. The departure is also consistent with the principle in clause 1(c) of the Guidelines (avoiding incentives to inefficiently avoid transmission charges).

8.2 Treatment of large de-rating of existing plant

94. In our Checkpoint 2B submission we proposed treating a large de-rating of plant as if it were disconnection of large plant of the same size and adjusting BBCs accordingly. In its feedback on our Checkpoint 2B submission, the Authority commented:

---

[51] Reference document #2 2019 Issues paper, Supplementary consultation, paragraph 4.2.
[52] Reference document #2 2019 Issues paper, Supplementary consultation, paragraph 4.13.

> As for de-rating, we agree that consistency with upgrading of plant would suggest a parallel treatment to 33(d) when there is a substantial de-rating of plant (i.e., the charges would be reduced consistent with the extent of the de-rating after the relevant benefit-based investments have been in operation for 10 years). However, as the guidelines do not provide for such a step, Transpower would need to rely on clause 2 to reduce the customer's charges in this case. [53]

95. As noted above, we propose to depart from the requirements of clause 33(d) of the Guidelines by treating a large de-rating of plant as if it were disconnection (or "closure" under clause 33(d)) of large plant.

96. We consider this departure is justified under clause 2 of the Guidelines.

    96.1. We consider the departure is not inconsistent with the intent of the Guidelines. A large de-rating of plant has the same impact on grid use, and benefits, as a plant disconnection of the same size, and in some cases it may be difficult to discern between the two (depending on how the de-rating was effected and what the minimum unit of "plant" is taken to be). It is therefore appropriate to treat these events in the same way. As the Authority has noted, this proposal is consistent with the Guidelines' treatment of upgrades as equivalent to the connection of new plant. It is also consistent with the purpose of BBCs in clause (iv) of the Guidelines, which is to recover the costs of BBIs according to customers' positive net private benefits.

    96.2. We consider the departure promotes the efficiency and competition limbs of the Authority's statutory objective. The discussion from our Checkpoint 2B submission reproduced in paragraph 76 about treating new and exiting load differently based on arbitrary factors also applies to treating plant decommissioning differently based on the arbitrary factor of whether the plant is de-rated or disconnected. We consider any such difference in treatment has the potential to:

    - incentivise inefficient operational decisions aimed only at avoiding BBCs, e.g. choosing to close plant entirely even though a business case for staying open at lower capacity would otherwise exist; and
    - adversely affect competitive neutrality between customers.

97. The departure is also consistent with the principles in clauses 1(c) (avoiding incentives to inefficiently avoid transmission charges) and 1(e) (avoiding discrimination between customers) of the Guidelines.

8.3 Treatment of distributor changes

98. In our Checkpoint 2B submission we proposed extending clause 33(a)(ii) of the Guidelines to cover increases in the use of electricity by distributors with local networks.[54] In its feedback on our Checkpoint 2B submission, the Authority commented:

> We also agree that Transpower's proposal to depart from the guidelines and include distributors' upgrades to transformers at a GXP as a substantial and sustained increase in load may be justifiable under clause 2 and the Authority will consider Transpower's proposals in this regard as part of considering the proposed TPM. [55]

---

[53] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph B.82.
[54] Reference document #47 Checkpoint 2B submission: Adjustments, paragraph 82.
[55] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph C.27.

99. As noted above, we propose to depart from the requirements of clause 33(a)(ii) of the Guidelines by treating local network transformer upgrades and new GXPs as potential substantial and sustained increases in load and therefore adjustment events.

100. We consider this departure is justified under clause 2 of the Guidelines.

    100.1. We consider the departure is not inconsistent with the intent of the Guidelines. The purpose of BBCs is to recover the costs of BBIs according to customers' positive net private benefits, and the positive net private benefits of a distributor include *"the positive net private benefit of <u>any parties</u> whose equipment is electrically connected to the interconnected grid through the [distributor's] network"* (clause (iv) of the Guidelines, emphasis added). An increase in local network load due to an accumulation of residential and commercial load growth has the same impact on the distributor's grid use, and deemed benefits, as the same growth coming from new large embedded plant, upgrades to such plant, or increases in electricity use by such plant..

    100.2. We consider the departure promotes the efficiency limb of the Authority's statutory objective. If grid-connected distributors are not exposed to increases in their BBC allocations for general load growth, this will tend to decrease their scrutiny of grid investment decisions and may encourage small-scale development in their networks when larger-scale development would be more efficient.

101. The departure is also consistent with clause 1(e) of the Guidelines (avoiding discrimination between customers).

TRANSPOWER

Chapter 11: Part G – Reassignment

30 June 2021

Contents: Chapter 11

1 Introduction

1. This chapter summarises and explains our proposals for the reassignment provisions of the proposed new TPM.
2. Reassignment is a type of adjustment that shifts the recovery of part of the cost of a benefit-based investment (**BBI**) from its benefit-based charge (**BBC**) to residual charges. As the Authority has said:[1]

> [Reassignment] occurs when [an interconnection] 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 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.

3. Other types of transmission charge adjustment are discussed in Chapters 8 (Residual charge), 10 (Adjustments), 12 (Transitional cap) and 13 (Prudent discount policy) of this paper.

[1] Reference document #1 2019 issues paper, paragraph B.185.

2 Requirements of the Guidelines

4. The Guidelines are prescriptive as to some elements of reassignment.

5. Clauses 34 to 40 of the Guidelines contain the requirements for reassignment.

Reassignment

34. The **TPM** must provide for a party to be able to make an application to Transpower for **reassignment** of **benefit-based charges**:

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

    b. where the **benefit-based investment** has a current (depreciated) 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**.

35. The **TPM** must provide that a **benefit-based investment** must, and may only, be subject to **reassignment** if, in Transpower's reasonable opinion, the circumstances which justify the **reassignment** are likely to be sustained and (over and above any changes which Transpower may take into account as a result of the application of clauses 31 to 33):

    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 from the grid of a single party, facility or plant 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.

36. The **TPM** must provide that, where Transpower receives an application for **reassignment** supported by evidence which Transpower in its reasonable opinion considers indicates that the conditions in clause 35 are likely to be met, it must undertake such investigations as it considers necessary for it to make an informed decision and then determine whether a **reassignment** is necessary under clause 35.

37. In setting a period of time for which a **post-2019 benefit-based investment** must have been c**ommissioned** 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.

38. The **TPM** must provide that, where Transpower determines that the circumstances which led to the **reassignment** no longer exist and that the depreciated value of the **investment** is $5 million or more after adjusting for inflation, 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.

39. The **TPM** must include a method for determining the value of a **benefit-based investment** following **reassignment** which is consistent with the change in forecast future demand for **transmission lines services** (over and above any changes taken into

account as a result of the application of clauses 31 to 33) which led to the **reassignment**, reversal or adjustment.

40. The TPM **must** provide that, where Transpower determines to carry out a **reassignment** with respect to a **benefit-based investment** or reverse or readjust the level of 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** (over and above any changes taken into account as a result of the application of clauses 31 to 33) which led to the **reassignment**, reversal or adjustment; and

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

3 Stakeholder engagement and process

3.1 TPM options consultation

6. In November 2020, we released a consultation paper seeking feedback on options for BBC allocation methods and methods for adjusting BBCs and residual charges (TPM options consultation paper). The BBC allocation and adjustments (including reassignment) components of the new TPM are interrelated, so we consulted on them at the same time.

7. As part of the TPM options consultation process we ran three online drop-in sessions. These were opportunities for stakeholders to ask questions and seek clarification about our thinking in the TPM options consultation paper.

8. The TPM options consultation paper, submissions, cross-submissions, and videos and transcripts of the three online drop-in sessions are available on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[2]

9. We have taken the submissions and cross-submissions into account in preparing the proposed TPM.

3.2 Checkpoint 2

10. In March 2021, we submitted our preliminary proposals for reassignment to the Authority as part of its Checkpoint 2 process (our Checkpoint 2B submission).[3]

11. In its feedback on our Checkpoint 2B submission, the Authority stated it was *"broadly comfortable with Transpower's approach to reassignment"*[4] and provided feedback on some reassignment-related matters in Appendices B and C.

[2] TPM Development: Options consultation process
[3] Reference document #47 Checkpoint 2B submission: Adjustments
[4] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph B.85.

12. We resubmitted our preliminary proposals for adjustments to the Authority in May 2021, responding to the matters the Authority had raised (our Checkpoint 2B resubmission).[5]

13. In its feedback on our Checkpoint 2B resubmission, the Authority commented:

> We welcome the changes to the adjustment sections of the proposed TPM. These now appear in most respects to be consistent with the TPM guidelines and the Authority's intent. However, we have identified some remaining points of feedback, which are discussed at Appendix D. [6]

14. Appendix D of the Authority's feedback did not contain any substantive feedback on reassignment. The Authority did provide some feedback on the reassignment provisions in the preliminary TPM drafting we provided with our Checkpoint 2B resubmission.

15. We have taken the Authority's feedback on our Checkpoint 2B submission and resubmission into account in preparing the proposed TPM.

4 Summary of our proposal

16. The proposed TPM deals with reassignment in Part G (clauses 95 to 107).

17. In summary, we propose:

    17.1. Only beneficiaries and their embedded plant owners will be eligible to apply for reassignment of a BBI (proposed definition of "eligible person"). This is discussed further in Section 5 below.

    17.2. We will publish annually a list of BBIs that meet the financial threshold for reassignment and identify which post-2019 BBIs are past the stand-down period for reassignment (clause 97(1) of the proposed TPM). As required by clause 34(b) of the Guidelines, to be eligible for reassignment, the current depreciated value[7] of a BBI must be at least $5m, inflation adjusted (clause 97(2) of the proposed TPM and paragraph (a) of the proposed definition of "eligible investment). The stand-down period will be 10 years since the relevant post-2019 BBI's commissioning date (paragraph (b)(i) of the proposed definition of "eligible BBI")). The stand-down period is discussed further in Section 6.

    17.3. An eligible BBI will be reassigned if its post-reassignment value is less than 80% of the BBI's current depreciated value and the circumstances justifying reassignment are sustained (clause 100(2) of the proposed TPM). The post-reassignment value of the BBI depends on a "BBI reassignment factor" calculated by reference to expected future loading and replacement costs for the grid investments comprised in the BBI (clause 101 of the proposed TPM). This is discussed further in Section 7.

    17.4. Reassignment will take effect as a scaling adjustment - the covered cost of the eligible BBI will be reduced for each year the BBI is subject to reassignment, so that all beneficiaries' BBCs for the BBI will be lower for that year (clauses 95 and 96 of the proposed TPM). The BBCs will not be reallocated unless the circumstances justifying

---

[5] Reference document #59 Checkpoint 2B resubmission: Adjustments

[6] Reference document #67 Letter from EA: Checkpoint 2B resubmission, page 2 and reference document # 68 Appendix D

[7] We propose to use the latest closing RAB value of all grid assets comprised in the BBI as the relevant depreciated value. We propose the financial threshold assessment take into account any reassignment the BBI is currently subject to.

the reassignment trigger one of the BBC reallocation adjustment triggers discussed in Chapter 10 (Adjustments). This is discussed further in Sections 8 and 10.

17.5. We will fully or partially reverse a reassignment if we determine the relevant BBI reassignment factor has increased and the circumstances causing the increase are sustained (clause 106(1) of the proposed TPM). This is discussed further in Section 9.

17.6. We will adopt broadly the same administrative and process requirements for reassignment applications as we are proposing for prudent discount applications. This will include application fees, application content requirements (both published outside the TPM), independent verification, initial screening before moving to detailed assessment, publication of applications and decisions, consultation, and independent review of decisions (clauses 16, 98, 99 and 102 to 105 of the proposed TPM). See Chapter 13 (Prudent discount policy) for a fuller discussion of these administrative and process requirements.

17.7. Also consistent with our proposals for prudent discounts, we will have the ability to publish a non-binding reassignment practice manual containing the assumptions and detailed methodologies we intend to apply to the assessment of reassignment applications (clause 107 of the proposed TPM). The merits of the proposed prudent discount, which we consider also support the proposed reassignment practice manual, are discussed in Chapter 13 (Prudent discount policy).

18. As noted above, the Guidelines prescribe several elements of our proposal for reassignment. The following sections discuss key aspects of our proposal where we have some discretion, including how our thinking has evolved.

5 Parties eligible to apply for reassignment

19. Clause 34(a) of the Guidelines requires the applicant for reassignment to be specified parties who have a material direct or indirect financial interest in the BBC for the eligible BBI to which the application relates. The Guidelines do not require the applicant to be a customer.

20. We propose to allow applicants for reassignment to be any party that directly or indirectly pays part of the BBC for the eligible BBI to which the application relates. We propose the pool of potential applicants will be:

20.1. those customers who are beneficiaries of the BBI; and

20.2. persons who own embedded plant connected to the plant of a beneficiary of the BBI, i.e. embedded consumers or generators,

(proposed definition of "eligible person"). There was unanimous support for this proposal from submitters on our TPM options consultation paper who commented on it.

21. We propose related parties of an eligible customer, embedded consumer or embedded generator (for example, shareholders) will not be able to apply for reassignment. We consider it appropriate for a related party of a customer or embedded consumer or generator (e.g. a shareholder) to go through the customer's, consumer's or generator's internal management and governance steps if the related party wishes reassignment to be

pursued. This would allow the eligible applicant to assess any competing interests before applying. As we noted in our Checkpoint 2B resubmission:[8]

> We expect in most cases interests will be aligned, but nonetheless it is important the customer, consumer or generator have the opportunity to factor in any competing interests that may exist. For example, it is possible the majority shareholder of a customer is a load customer in its own right and would therefore oppose reassignment. It would be anomalous if a minority shareholder of the customer could use that status to apply for reassignment despite the competing interest of the majority shareholder. The result could be the minority shareholder's application being opposed by the customer through which the minority shareholder has standing to apply.

22. In paragraph B.89 of its feedback on our Checkpoint 2B submission, the Authority expressed a view that our proposal is a departure from the requirements of clause 34(a) of the Guidelines. We disagree. Our proposal is merely defining what *"material direct or indirect financial interest"* in clause 34(a) means, in the same way as we are proposing to define the terms *"large"* and *"substantial"* used in the Guidelines. This is consistent with the principle in clause 1(b)(iii) of the Guidelines (certainty, including through limiting the need for Transpower to exercise discretion). The Authority did not reiterate its previous view in its feedback on our Checkpoint 2B resubmission.

23. We also consider our proposal is consistent with the efficiency limb of the Authority's statutory objective. It would be most efficient if differences of opinion internal to the applicant for reassignment were resolved before the application is submitted to Transpower for assessment.

6 Stand-down period

24. Clause 35(b) of the Guidelines requires a stand-down period before a reassignment application can be made for a post-2019 BBI, except where the circumstances justifying the reassignment are *"the disconnection from the grid of a single party, facility or plant"*.

25. The Guidelines do not define what a *"single party, facility or plant"* is. Nor do the Guidelines specify how long the stand-down period must be. However, clause 37 of the Guidelines requires the stand-down 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.

26. We propose:

    26.1. the stand-down period would be 10 years from when the relevant post-2019 BBI was commissioned (paragraph (b)(i) of the proposed definition of "eligible BBI").[9] We consider this to be an appropriate period because:

    - 10 years is a commonly adopted half-life for explicit cash flow forecasting;

[8] Reference document #59 Checkpoint 2B resubmission: Adjustments, paragraph 45.

[9] There was majority support for the 10-year proposal from submitters on our TPM consultation paper who commented on it. We propose the BBI will be deemed to be commissioned when the first grid asset or transmission alternative comprised in it is commissioned or commenced (clause 6(2) of the proposed TPM).

- post-2019 BBIs will have a relatively long economic life, typically 45 to 55 years.[10] A 10-year stand-down period will leave many years of economic life over which a reassignment can affect transmission charges; and
- We consider the period is long enough to satisfy the "negligible impact" requirement in clause 37 of the Guidelines (in combination with the inherent uncertainty as to whether a future application for reassignment would be successful); and

26.2. *"disconnection from the grid of a single party, facility or plant"* would mean:

- permanent disconnection of a customer at a connection location (not just a single point of connection to the grid at a connection location); or
- permanent disconnection of consuming or generating plant from the grid,[11]

(paragraphs (b)(i) and (b)(ii) of the definition of "eligible BBI"). We consider this is an appropriate specification of the disconnection threshold because a lesser form of disconnection from the grid is unlikely to meet the 80% threshold for post-reassignment value.

7 Post-reassignment value

27. Clause 35 of the Guidelines says an eligible BBI may only be subject to reassignment if the value of the BBI post-reassignment is less than 80% of its current (depreciated) value and we consider the circumstances justifying reassignment are likely to be sustained.[12]

28. In our TPM options consultation paper and Checkpoint 2B submission, we discussed options for determining this difference in value. An option we put forward was to use a "hybrid ODHC" valuation method, which would be a combination of the relatively well-established optimised depreciated replacement cost (ODRC), optimised deprival value (ODV) and depreciated historic cost (DHC) valuation methods.

29. In its feedback on our Checkpoint 2B submission, the Authority said:[13]

> B.85 We are broadly comfortable with Transpower's approach to reassignment. We appreciate Transpower continuing to carefully consider the method for calculating reassignment value, and specifically it considering a simpler approach (such as a rule of thumb), as we have previously suggested may be desirable.
>
> B.86 We would note that several factors support the choice of a simpler approach, including:
>
> (a) a complex method could be expensive for applicants, which might defeat the intention of the reassignment provision if a high application fee discouraged applications by small distributors – given that concern about the potential impacts

---

10 Reference document #71 Transpower Capex IM, Schedule A (standard physical asset lives).

11 We do not propose to treat a large de-rating of plant as a disconnection for the purposes of the stand-down period. We do not consider the stand-down period is a significant enough matter to justify a potential departure from the requirements of clause 35(b)(i) of the Guidelines.

12 As discussed in Chapter 10 (Adjustments), for all purposes in the proposed TPM "sustained" means expected to persist for at least five years (clause 8 of the proposed TPM).

13 Reference document #56 Letter from EA: Checkpoint 2B submission, paragraphs B85-B87

of the exit of an industrial customer on small distributors was one of the Authority's reasons for proposing the reassignment provision

(b) we do not see any compelling reasons why the reassignment provision must use the same methodology as the [stand-alone cost prudent discount] provisions. These two parts of the proposed TPM have different purposes and may use different methods

(c) clause 1(b)ii of the guidelines (relating to simplicity) and clause 1(b)iv (relating to administration cost) would appear to favour a relatively simple, low-cost approach, rather than a more complex and costly approach.

B.87 The Authority reiterates its view that the basis for reassignment may be relatively simple, perhaps using a rule of thumb, even if that means that the reassignment value is not precise. We encourage Transpower to consider whether an approach such as the simple loading versus cost curve described in Transpower's submission might be appropriate.

30. Having considered this feedback, we propose to adopt a simple approach to determining the availability of reassignment, and the post-reassignment value, for an eligible BBI. On balance, we consider the benefits of adopting a simple and more mechanistic approach are likely to outweigh the potential disadvantages of such an approach we summarised in paragraph 138 of our Checkpoint 2 submission.

31. We propose to calculate a "BBI reassignment factor" for an eligible BBI as follows:

31.1. determine a "forecast loading period" for the BBI, being a period at least 10 years into the future (clause 101(1) of the proposed TPM). We have chosen 10 years for the minimum forecast loading period because, in combination with the 10-year stand down period for reassignment, this provides a total period (at least 20 years) within which the bulk of the benefits of a BBI would normally be expected to emerge, given that the typical calculation period for high-value investment decisions is 20 years;

31.2. for each grid investment comprised in the BBI,[14] determine a peak electrical loading ("forecast peak loading") for the grid investment over the forecast loading period (clause 101(2) of the proposed TPM);

31.3. for each grid investment comprised in the BBI, determine an "investment reassignment factor", being the proportion of the grid investment's full replacement cost we would expect to incur to replace the grid investment with a grid investment of the same type to meet the forecast peak loading and reasonable grid contingencies, but no more (clause 101(3) of the proposed TPM); and

31.4. take a covered-cost weighted average of the investment reassignment factors (clause 101(4) of the proposed TPM).

32. If the eligible BBI's BBI reassignment factor is less than 80% and the circumstances justifying reassignment are sustained, the BBI would be proportionately reassigned (clause 100(2) of the proposed TPM). Mechanically, this would be achieved by scaling down the BBI's covered cost for each pricing year by the BBI reassignment factor until the BBI ceases to be subject to reassignment (clauses 95 and 96 of the proposed TPM).

[14] The proposed TPM contemplates a BBI may contain more than one grid investment (investment in a grid asset or transmission alternative).

33. We may publish reassignment factor guidance in the reassignment practice manual to flesh out the relationship between capacity-adjusted replacement cost and forecast peak loading for one or more investment types, although the availability of reassignment would not depend on relevant reassignment guidance having been published (clause 101(5) of the proposed TPM).

8 Implementation of reassignment

34. As noted above, we propose reassignment will take effect as a scaling adjustment - the covered cost of the eligible BBI will be reduced for each year the BBI is subject to reassignment, so that all beneficiaries' BBCs for the BBI will be lower for that year.

35. We propose reassignment would not, by itself, result in any reallocation of the BBCs for the eligible BBI. Reassignment is a response to the BBI being over-sized compared to forecast future demand for it (clause 39 of the Guidelines). Reallocation is not a necessary or appropriate response to over-sizing. However, it is possible the circumstances justifying a reassignment will also be a reallocation adjustment trigger under clause 33 of the Guidelines. Customer exit is an example. In that case we would determine the appropriate reallocation in accordance with the new TPM provisions dealing with customer exit (see Chapter 10 (Adjustments)). As a separate exercise, we would assess any application we received for reassignment. The end result may be both a scaling and reallocation adjustment of the BBCs for the BBI. There was unanimous support for this proposal from submitters on our TPM options consultation paper who commented on it.

36. Our proposal not to automatically reallocate the BBCs for an eligible BBI when it is reassigned is a departure from the requirements of clause 40(b) of the Guidelines. This is discussed in Section 10. We note that, because we propose to treat reassignment as a scaling adjustment only, the requirement in clauses 35 and 39 of the Guidelines that reassignment be over and above any changes under clauses 31 to 33 of the Guidelines will always be satisfied:

    36.1. Clause 33 of the Guidelines is exclusively about triggers for reallocation adjustments, so any scaling adjustment for reassignment will never be duplicated by an adjustment under clause 33 (although, as noted above, a separate reallocation adjustment under clause 33 may be appropriate depending on the circumstances justifying the reassignment).

    36.2. Clauses 31 and 32 of the Guidelines do contain triggers for scaling adjustments, but we do not consider those triggers (non-capex changes to covered cost and damage) could ever constitute circumstances justifying a reassignment.

37. There does not need to be a method in the TPM to adjust residual charges in the specific case of a reassignment (clause 40(c) of the Guidelines). Reassignment will reduce the amount of our recoverable revenue recovered through BBCs, which will automatically increase the amount of residual revenue to be recovered through residual charges.

38. We propose to implement a reassignment from the start of the pricing year that starts at least six months after the reassignment is confirmed, or an earlier pricing year if we determine it is practicable to do so (clause 95 of the proposed TPM and paragraph (c) of the

proposed definition of "start pricing year"). This will allow us to factor the reassignment into our normal annual pricing process.[15]

9 Reversal of reassignment

39. Clause 38 of the Guidelines requires a reassignment to be reversed or adjusted (partially reversed) if:

    39.1. we consider the circumstances that justified the reassignment no longer exist; and

    39.2. the relevant BBI has a depreciated value of at least the financial threshold for reassignment (being $5m, inflation adjusted – clause 97(2) of the proposed TPM).

40. This is implemented in clause 106 of the proposed TPM.

41. The Guidelines do not require an application before a reassignment is fully or partially reversed. There is nothing in the Guidelines requiring a reassignment to be in place for a minimum period of time before it can be fully or partially reversed. We propose we would be able to review and fully or partially reverse a reassignment at any time. If we did propose to reverse a reassignment, the same process requirements as apply to granting a reassignment application would apply (clause 106(2) of the proposed TPM).

42. If we determined the BBI's BBI reassignment factor is 0.8 or more, we would fully reverse the reassignment (clause 106(3) of the proposed TPM). This is because the BBI would not have been reassigned in the first place with a BBI reassignment factor of 0.8 or more.

43. Unison/Centralines submitted in response to our TPM options consultation paper that reassigned amounts should be "paid back" by the relevant beneficiaries after a reassignment is reversed. We disagree. We do not consider a pay back regime would be consistent with the intent of reassignment, which is to provide relief to the relevant beneficiaries if the expected benefits of a BBI fail to materialise to a significant extent. A pay back regime would result in the beneficiaries paying for the non-existent benefits later.

10 Consistency with the Guidelines

44. Except for the proposed departure discussed below, we consider our proposals for adjustments to be fully compliant with the Guidelines. See the Guidelines compliance matrix attached to this paper.

10.1 No automatic reallocation in response to reassignment

45. As noted above, we propose to not automatically reallocate the BBCs for an eligible BBI when it is reassigned. This is a departure from the requirements of clause 40(b) of the Guidelines.

46. We consider this departure is justified under clause 2 of the Guidelines.

---

[15] Under clause 41.5(a) of the benchmark transmission agreement, we must give at least three months' notice of a change to transmission charges that will be effective at the start of a pricing year. Before we notify customers, the new transmission charges need to be calculated, audited and approved by our Board.

46.1. We consider the departure is not inconsistent with the intent of the Guidelines. BBCs are intended to be fixed-like charges. As the Authority said in its feedback on our Checkpoint 2B submission:

> We consider that the Authority' intent, that once allocations have been made, they should not change except in very specific circumstances, is clear from clause 24 of the guidelines as well as being set out in the Decision Paper from paragraph 9.83 onwards. [16]

The Guidelines therefore specify in clauses 33, 41 and 42 particular situations in which BBCs may be reallocated. It would be out of step with that intent if clause 40(b) of the Guidelines effectively added a reallocation adjustment event of "if something else happens or does not happen."

46.2. We consider the departure promotes the efficiency limb of the Authority's statutory objective. The Authority stated its reasoning for fixed-like BBCs in its 2020 Decision (emphasis added):[17]

> **Benefit-based charge to be largely fixed**
>
> 9.82 Submissions on this proposal were mixed. Some stakeholders endorsed the proposal and the Authority's reasoning. However, many parties disagreed with our position.
>
> 9.83 Having considered the matters raised in submissions, <u>the Authority's view remains that it would promote efficient investment and the efficient operation of the electricity industry for the benefit-based charge to generally have a fixed allocation, which could be revised in certain limited circumstances.</u>
>
> 9.84 This decision strikes a balance between competing considerations. The benefit-based charge is intended to reveal information on efficient costs and benefits at the time a grid investment is proposed. To preserve the incentives for this and to discourage inefficient charge avoidance behaviour, it is critical that the guidelines limit the scope for revisiting the allocation of the benefit-based charge over time…

47. The departure is also consistent with the principle in clause 1(b)(iii) of the Guidelines (certainty, including by limiting the need for Transpower to exercise discretion).

---

[16] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph B.72.

[17] Reference document #3 2020 Decision

TRANSPOWER

Chapter 12: Part H - Transitional Cap

30 June 2021

Contents: Chapter 12

1 Introduction

1. This chapter summarises and explains our proposals for the transitional cap provisions of the proposed new TPM.

2. The transitional cap applies to certain load customers' residual charges and benefit-based charges (**BBCs**) for the historical benefit-based investments (**BBIs**) in Schedule 1 of the Guidelines/Appendix A of the proposed TPM.

2 Requirements of the Guidelines

3. Clause (vii) of the Guidelines states the purpose of the TPC.

> The purpose of the transitional cap on certain **transmission charges** is to limit electricity bill 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 the customer actually incurred in respect of 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 cap.

4. The transitional cap is main component 5 of the Guidelines.

> **Main component 5: transitional cap on transmission charges**
>
> 49. Subject to clause 53, the TPM must provide for a cap on the sum (excluding GST) of each **existing load customer's**:
>
> a. **benefit-based charges** in respect of the **benefit-based investments** included in Schedule 1;
>
> b. **residual charge**; and
>
> c. any surcharge imposed by the operation of clause 51.

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

a. the difference between a distributor's **transmission charges** subject to the cap as set out in clause 49, and 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 x (0.035 + CPI + L)

where:

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

B = C + P * V

and where:

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

L is the proportionate increase in the distributor's load in MWh 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 the Schedule 8 Report on Billed Quantities and Line Charges Revenues of the Electricity Distribution Information Disclosure Determination 2012 (as amended from time to time);

P is the volume weighted average of wholesale energy prices at the distributor's grid exit point or grid exit points for the 5 **pricing 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 distributor's **gross** energy usage as determined by the reconciliation manager; and

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

b. the difference between a direct consumer's **transmission charges** subject to the cap as set out in clause 49, and its **transmission charges** minus its **connection charges** in the 2019/20 **pricing year**, to be limited to no more than:

B x (0.035 + 0.02 x Y + CPI + L)

where:

B is the estimated total electricity bill of that direct consumer in the 2019/20 **pricing year** (expressed in dollars, excluding GST), 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 start of the 2019/20 **pricing year** minus 5;

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

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

T is the direct consumer's total **transmission charge** (including any **connection charge**) 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 grid exit points for the 5 **pricing 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 direct consumer's **gross** energy usage as determined by the **reconciliation manager**; and

V is the direct consumer's total **gross** annual energy usage in the 2019/20 **pricing year** in MWh obtained from the reconciliation manager;

c. the cap to be permanently removed:

(i) for a particular **existing 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 **existing load customer's transmission charges** subject to the cap as set out in clause 49; and

(ii) in its entirety, by the end of the 2038/39 **pricing year**.

51. To the extent that the cap results in a reduction in **transmission charges** for one or more **existing load customers**, the revenue so forgone is to be recovered by a surcharge on and proportional to the total of the charges listed in clause 49 for each designated transmission customer.

52. For the avoidance of doubt, 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 cap as set out in clause 49 meet the conditions in clause 50.

53. The cap provisions must not prevent Transpower from recovering its **recoverable revenue**.

3 Stakeholder engagement and process

3.1 Consultation

5. We did not consult on options for the transitional cap. The Guidelines are prescriptive about the method for the transitional cap, so there is limited scope for us to consider different options. We chose to focus our stakeholder engagement on other matters.

3.2 Checkpoint 2

6. In November 2020, we submitted our preliminary proposals for the transitional cap to the Authority as part of its Checkpoint 2 process (our Checkpoint 2A submission).[1] Our Checkpoint 2A submission included preliminary TPM drafting for the transitional cap.

7. In its feedback on our Checkpoint 2A submission,[2] the Authority said it considered most of the preliminary TPM drafting for the transitional cap to be appropriate. However, in the Authority's view, to be consistent with the Guidelines:

   7.1. *"the cap should not apply to benefit-based charges for post-2019 investments"* (this was a drafting error on our part that has been corrected in the proposed TPM); and

   7.2. *"the cap should be available to generation customers, including those with significant load connected to their network (in their capacity as load customers)"*.

8. We resubmitted our preliminary proposals for the transitional cap to the Authority in January 2021, responding to the matters the Authority had raised (our Checkpoint 2A resubmission).[3] In response to our Checkpoint 2A resubmission, the Authority provided further feedback on the application of the transitional cap to grid-connected generators and some other matters.[4]

9. We have taken the Authority's feedback on our Checkpoint 2A submission and resubmission into account in preparing the proposed TPM.[5]

4 Summary of our proposal

10. As noted above, the Guidelines are prescriptive about the method for the transitional cap. Part H of the proposed TPM implements the method in the Guidelines with two departures (discussed in Section 7).

11. In summary, we propose:

    11.1. The transitional cap will apply to customers, other than generators, who existed during pricing year 2019 and at least two pricing years before that (paragraph (a) of the proposed definition of "capped customer"). The exclusion of generators is discussed in Section 5.

    11.2. A capped customer's transmission charges for each pricing year before pricing year 2038 will be reduced by the minimum amount necessary (if

1 Reference document #31 Checkpoint 2 submission: Residual Charge and Transitional Cap
2 Reference document #35 Letter from EA: Checkpoint 2A submission
3 Reference document # 42 Checkpoint 2 resubmission: Residual Charge and Transitional Cap
4 Reference document # 44 Letter from EA: Checkpoint 2A resubmission Residual Charge and Transitional Cap
5 The Authority had no further feedback on the transitional cap in its final feedback (reference document # 67 Letter from EA: Checkpoint 2B resubmission).

any) to ensure the cap condition is satisfied (clauses 108(1), 108(2) and 109 of the proposed TPM and proposed definition of "capped charges").

11.3. Any applicable prudent discount agreement is factored into the application of the cap condition (clause 108(5) of the proposed TPM).

11.4. After the first pricing year, a capped customer loses the benefit of the transitional cap if it did not apply to the customer in the previous pricing year (paragraph (b) of the proposed definition of "capped customer").[6]

11.5. The transitional cap must not result in Transpower recovering less than recoverable revenue for a pricing year. If necessary, Transpower will reduce customers' cap reductions on a pro rata basis to ensure full recovery (clause 108(6) of the proposed TPM).

11.6. The total cap reduction for a pricing year is recovered from customers in proportion to their total annual residual charges and BBCs for the BBIs in Schedule 1 of the Guidelines/Appendix A of the proposed TPM (clause 110 of the proposed TPM and proposed definition of "cap recovery-relevant charges"). This recovery is affected through a transmission charge called the "cap recovery charge", which itself is part of the capped charges.[7]

12. There are some minor differences in terminology between the Guidelines and the proposed TPM, as shown in the following table:

Guidelines term/variable	Equivalent TPM term/variable
Estimated total electricity bill, B	Notional electricity bill, NEB_{c19}
Proportionate change in Consumer Price Index, CPI	Proportionate change in CPI, ΔCPI_n
Proportionate increase in load, L	Proportionate increase in total gross energy, ΔTGE_{cn}
Distributor's total line charge revenue, C	Distributor's total line charge revenue, LC_{c19}
Direct consumer's total transmission charge, T	Direct consumer's total annual transmission charges, LC_{c19}
Volume weighted average of wholesale energy prices, P	Volume weighted average of final prices, P_{c19}
Gross annual energy usage, V	Total gross energy, TGE_{c19}

6 We will start BBCs for low-value post-2019 BBIs from the first pricing year, so there will be no delay under clause 50(c)(i) of the Guidelines.

7 Clause 51 of the Guidelines requires the cap recovery-relevant charges to include the cap recovery charge itself, which is not possible because the cap recovery charge cannot be an output of the relevant calculation as well as an input. Our proposal is technically compliant with clause 51 of the Guidelines because the cap recovery charge is "proportional to" (equal to) itself.

5 No application of transitional cap to grid-connected generators

13. In its feedback on our Checkpoint 2A submission, the Authority, responding to our proposal to exclude generators from the transitional cap, noted that "*some generators are also load customers to the extent they draw electricity from the grid and to the extent that there is load embedded behind their grid connection point.*" The Authority was concerned any such generator "*would be excluded from having the cap applied to them, even if the guidelines suggest they should receive the benefit of the cap*".[8]

14. We do not consider the Guidelines require the transitional cap to apply to grid-connected generators *"to the extent that there is load embedded behind their grid connection point."*

    14.1. A grid-connected generator is not a "load customer", as defined in the Guidelines, other than in respect of its offtake. The definition of "load customer" in the Guidelines does not include a customer whose equipment serves embedded load behind the customer's point of connection to the grid.[9]

    14.2. Clause 50 of the Guidelines does not contain a formula for calculating the difference cap for a generator that is not a direct consumer. Generators are not mentioned at all in clause 50.

15. We do not propose to depart from the Guidelines by designing new cap calculus for grid-connected generators in respect of embedded load. The cap calculus in the Guidelines is already highly prescriptive and nuanced. We consider using clause 2 of the Guidelines to design new cap calculus stretches the boundaries of what we can properly do to develop the proposed TPM.

16. Further, we do not consider the direct consumer transitional cap in clause 50(b) of the Guidelines should apply to a generator who is occasionally a direct consumer.[10] This would not yield a sensible result because the generator's notional electricity bill for pricing year 2019, in the generator's capacity as a direct consumer, will likely be very low. This would not be a problem if only the generator's residual charge were being capped, but the capped charges include the BBCs for the Schedule 1/Appendix A BBIs (for example, Contact's 24.07% and 21.39% shares of the covered costs of the LSI Reliability and Wairakei Ring investments). Accordingly, the cap would be far too low relative to the transmission charges being capped, with very significant wealth transfer impacts and possibly meaning the cap condition never reaches an equilibrium. This is a

---

8 Reference document #35 Letter from EA: Checkpoint 2A submission, paragraphs A.30 and A.31.

9 As discussed in Chapter 8 (Residual charges), we do propose to depart from the requirements of the Guidelines by treating generators with embedded load as load customers and allocating them a residual charge for that load.

10 Under the Code, a "consumer", and therefore a "direct consumer", includes a generator "supplied with electricity for its own consumption".

departure from the requirements of clause 50(b) of the Guidelines, which is discussed further in Section 7.

17. We consider our proposed approach is reinforced by the fact the Authority did not apply the transitional cap to generators, or to any load customers who are not grid-connected distributors or direct consumers, in the indicative pricing in its 2020 Decision (paragraphs 16.23 to 16.28 and Figure 13).

18. In any event, there is no current configuration where we treat a grid-connected generator as having embedded load. There are some "intermingled" load and generation configurations (such as the dairy factory and co-generation plant at Whareroa) but those are all treated as grid-connected load with embedded generation.

19. Accordingly, the proposed TPM retains the exclusion of grid-connected generators from the transitional cap (paragraph (a) of the proposed definition of "capped customer").

20. We acknowledge that the Authority does not share our view that applying the transitional cap to grid-connected generators would be a departure from the requirements of the Guidelines.[11] However, the Authority has accepted our preliminary proposal *"at this point"* on the basis that the Authority's main concern (grid-connected generators with embedded load) appears not to arise in practice.

6 Existing load customers

21. Clause 49 of the Guidelines says the transitional cap only applies to an "existing load customer", which means:

> a **load customer** which, in Transpower's reasonable opinion, was fully operational prior to the beginning of the 2019/20 **pricing year**.

22. "Fully operational" is not defined in the Guidelines. As a proxy, we propose a capped customer must have been a customer during pricing year 2019 and during at least two pricing years preceding pricing year 2019 to be considered "fully operational" (paragraph (a) of the proposed definition of "capped customer").[12] We consider it would be unusual for a customer not to have ramped up its production to somewhere near "full operation" within two to three years of connecting to the grid.

23. This proposal is consistent with our general approach of quantifying thresholds in the proposed TPM where possible. This approach is consistent with the principle in clause 1(b)(iii) of the Guidelines (certainty, including through limiting the need for Transpower to exercise discretion).

[11] Reference document #44 Letter from EA: Checkpoint 2A resubmission Residual Charge and Transitional Cap. The Authority's interpretation is based on clause 7 of the Guidelines. The Authority's interpretation does not engage the definition of "load customer" in the Guidelines or any of the clauses relating directly to the transitional cap.

[12] We note that a capped load customer will need to have been a connected asset owner during pricing year 2019 for the inputs to the calculation of the customer's difference cap to be available, and during at least one pricing year before that to have been "operational" before the start of pricing year 2019.

7 Consistency with the Guidelines

24. Except for the matters discussed below, we consider our proposals for the transitional cap are fully compliant with the Guidelines. See the Guidelines compliance matrix attached to this paper.

7.1 No cap for grid-connected generators as direct consumers

25. As noted above, we consider our proposal not to apply the transitional cap to generators to the extent they are direct consumers to be a departure from the requirements of clause 50(b) of the Guidelines.

26. We consider this departure is justified under clause 2 of the Guidelines.

    26.1. We consider the departure is not inconsistent with the intent of the Guidelines. In its 2020 Decision, consistent with the reference to limiting "*price shock*" in clause (vii) of the Guidelines, the Authority said the purpose of the transitional cap is *"to limit the increase in total electricity bills that would otherwise be caused by implementing a new TPM"*. For the reason in paragraph 16, applying the transitional cap to generators in their capacities as direct consumers would go far beyond limiting price shock arising from the new TPM – it would result in a windfall gain to generators by capping some of their BBCs as well as residual charges (contrary to the discussion in paragraphs 13.21 and 13.22 of the 2020 Decision). Further, chapter 13 of the 2020 Decision consistently refers to distributors and "industrial" customers having the benefit of the transitional cap. In the Code, "industrial process" means *"a process that has a primary purpose of producing an output other than electricity"*.

    26.2. We consider the departure promotes the efficiency and competition limbs of the Authority's statutory objective. Large and seemingly unintended wealth transfers in favour of grid-connected generators would create inefficient pricing signals, particularly, in this case, in respect of the pre-2019 BBIs in Schedule 1 of the Guidelines/Appendix A of the proposed TPM. Competitive neutrality between grid-connected generators and embedded generators would be compromised, with the former advantaged over the latter.

27. The departure is also consistent with the principle in clause 1(e) of the Guidelines (avoiding discrimination between customers).

7.2 Source of gross energy information

28. In clause 109(2) of the proposed TPM, neither the gross energy weighting for the variable P_{19} nor the capped load customer's total gross energy for the variable TGE_{19} needs to be obtained from the reconciliation manager. This proposal is a departure from the requirements of clauses 50(a) and 50(b) of the Guidelines, which require this gross energy information to come from the reconciliation manager.

29. For distributor total gross energy information, we propose to use the regulated disclosures for electricity distribution businesses.[13] For other total gross energy information we may use a variety of sources, including the reconciliation manager.

30. We consider this departure is justified under clause 2 of the Guidelines.

    30.1. We consider the departure is not inconsistent with the intent of the Guidelines. The calculation of the customer's notional electricity bill for pricing year 2019 does not change substantively. The departure goes only to the source of the input information

    30.2. We consider the departure promotes the efficiency limb of the Authority's statutory objective. Without the departure, the cost of administering the TPM may increase because Transpower will not be able to use information it already holds or can obtain from alternative, less costly (or costless) sources.

31. The departure is also consistent with the principle in clause 1(b) of the Guidelines (practical considerations). Our proposal may reduce the cost of administering the new TPM, and, as the Authority has pointed out, the reconciliation manager does not have all the necessary embedded load and generation information for calculating gross energy [14] The departure addresses this problem.

[13] Electricity Distribution Information Disclosure Determination 2012 [2012] NZCC 22.

[14] Reference document #35 Letter from EA: Checkpoint 2A submission, paragraph A.9.

TRANSPOWER

Chapter 13: Part I - Prudent Discount Policy

30 June 2021

Contents: Chapter 13

1 Introduction

1. This chapter summarises and explains the reasons for the prudent discount policy (**PDP**) in the proposed new TPM.
2. The Guidelines require the TPM to include a PDP comprising an inefficient bypass prudent discount (**IBPD**), which was provided for in the PDP provisions in the previous version of the Guidelines, and a new stand-alone cost prudent discount (**SACPD**).
3. The IBPD is a prudent discount available in situations where it is feasible and commercially viable for a customer to inefficiently bypass the grid by some means, including by investing in new generating plant.[1] There are two current IBPD agreements (for Waipori and Matahina/Aniwhenua), both of which relate to the notional embedding of a generator in a distributor's network. There is also an old notional embedding agreement (for Blackpoint), which is what IBPD agreements used to be called.[2]
4. The SACPD will be a new type of prudent discount to ensure a customer does not pay more in transmission charges than the efficient stand-alone cost of the transmission services they receive from the interconnected grid. The efficient stand-alone cost will be determined by

---

[1] The current TPM does not allow an investment in new generation to be the basis for an IBPD (definition of "alternative project" in clause 3). The Guidelines do not include that restriction. Clause 45 of the Guidelines allows for any type of "alternative supply", which may include new generating plant (see Reference document #1 2019 issues paper, paragraph B.252 and footnote 245).

[2] Details of these agreements are published on Transpower's website at https://www.transpower.co.nz/industry/revenue-and-pricing/pricing.

reference to a hypothetical investment that only supplies the customer. The hypothetical investment will need to be commercially viable for the customer but can differ from an IBPD in that it does not need to be feasible to build from a consenting or property right perspective.

2 Requirements of the Guidelines

5. Clause (vi) of the Guidelines states the intent of the PDP:

The purpose of the prudent discount policy is to allow Transpower to discount the **transmission charges** of a designated transmission customer if the customer:

a. would otherwise pay more than the stand-alone cost of **transmission lines services** equivalent to the services it receives from the **interconnected grid** (calculated based on a hypothetical **investment** to supply that customer); or

b. would find it viable to inefficiently bypass the grid (including inefficiently disconnecting from the grid in favour of alternative supply).

6. Clauses 45 to 48 of the Guidelines contain the requirements for to the PDP:

Main component 4: prudent discount policy

45. The **TPM** must provide for a prudent discount policy that encourages existing and prospective 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.

46. 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 45; 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 grid and the economic costs incurred by the designated transmission customer if it proceeded with the relevant action described in clause 45.

47. The **TPM** must further:

a. include a method for determining the efficient standalone cost of the **transmission lines services** a designated transmission customer receives based on the hypothetical **investment** that would be required to supply solely that designated transmission customer;

b. ensure that the method provided for in clause 47(a) results in a standalone cost which, in Transpower's reasonable opinion, approximates the cost of supplying transmission services that are of equivalent value to the customer, including in terms of access to energy, quality of energy supplied, reliability, security of supply, the cost of resource or other regulatory consents, and such other matters as Transpower considers relevant; and

c. provide that a prudent discount must be available where and to the extent that a designated transmission customer's **transmission charges** exceed the standalone cost of the **transmission lines services** it receives.

48. The **TPM** must detail practical ways to facilitate greater transparency on the matter of prudent discounts.

7. Clauses (vi)(b), 45 and 46 relate to the IBPD and reflect the current PDP and clause 18 of the previous Guidelines.[3] Clauses (vi)(a) and 47 relate to the SACPD.

3 Stakeholder engagement and process

3.1 Consultation

8. In October 2020, we released a consultation paper seeking feedback on options for the PDP, including indicative TPM drafting. The PDP consultation paper, submissions and cross-submissions are published on Transpower's website, along with a summary of, and our responses to, the submissions and cross-submissions.[4]

9. We have taken the submissions and cross-submissions into account in preparing the proposed TPM.

3.2 Checkpoint 2

10. In March 2021, we submitted our preliminary proposals for the PDP the Authority as part of its Checkpoint 2 process.[5]

11. In its feedback on our Checkpoint 2B submission, the Authority commented:

> We consider that Transpower's proposed approach to the PDP is likely to be acceptable, however we would like to consider some points further and so we are requesting resubmission.[6]

12. The Authority asked us to consider and resubmit on a number of substantive issues concerning the PDP, set out in Appendix B of its feedback. The Authority also provided some additional points for consideration in Appendix C.

13. We resubmitted our preliminary proposals for the PDP to the Authority in May 2021, responding to the matters the Authority had raised.[7]

14. In its feedback on our Checkpoint 2B resubmission, the Authority commented:

> The Authority considers that Transpower's new proposed approach to funding PDs is likely consistent with the Guidelines and is likely to be acceptable. Because these costs would be borne by only a subset of generators (those that benefit from certain investments), as opposed to all generators, it appears less likely to result in costs being passed through to load customers via the wholesale market in an inefficient manner.
>
> …
>
> We invite Transpower to consider some potential amendments to the PDP section of the preliminary TPM drafting (Appendix E) to improve regulatory certainty: to specify that the

[3] Clause 18 of the previous TPM guidelines states "A prudent discount policy should be adopted to ensure that inefficient by-pass of the existing grid does not occur. Transpower should detail as part of the pricing methodology practical ways to facilitate greater transparency on this matter."

[4] TPM Development: Prudent Discount Policy consultation process

[5] Reference document #51 Checkpoint 2B submission: Prudent Discount Policy

[6] Reference document #56 Letter from EA: Checkpoint 2B submission

[7] Reference document #51 Checkpoint 2B resubmission: Prudent Discount Policy

PD Manual will be binding on Transpower and to set a timeframe for Transpower's consideration of PD application and for independent reviews.[8]

15. We have taken the Authority's feedback on our Checkpoint 2B submission and resubmission into account in preparing the proposed TPM.

4 Summary of our proposal

16. Part I of the TPM drafting relates to the PDP. We have divided the PDP into four subparts. The first subpart (clauses 111 to 123) contains common rules applying to both types of prudent discount and applications for them. The second subpart (clauses 124 to 129) applies to IBPDs only. The third subpart (clauses 130 to 134) applies to SACPDs only. The fourth subpart (clause 135) relates to how prudent discounts are funded.

17. Our proposal ensures consistency between the processes, terminology and criteria for both types of prudent discount, and avoids unnecessary repetition. We have also retained familiar terminology and concepts from the current PDP.

18. A summary of our PDP proposal is that:

19. **There will be two types of prudent discount:** An IBPD is to help ensure the TPM does not incentivise a customer to invest in an alternative project that would allow the customer to reduce its own transmission charges, but would be inefficient. A SACPD is to help ensure the TPM does not result in a customer paying transmission charges that exceed the efficient stand-alone cost of the transmission services the customer receives.

20. **Process requirements:** As is the case currently, a customer will need to apply to Transpower to obtain a prudent discount. The process for Transpower to consider an application includes that:

    20.1 Transpower must consult on Prudent Discount applications.

    20.2 An applicant can challenge Transpower's PDP decision by referring aspects of it to an independent expert for review. The independent expert's decision will be binding.[9]

    20.3 All decisions to not approve or reject a customer's application for a prudent discount will be published (excluding commercially sensitive information).

21. **Prudent discount practice manual:** Transpower may publish a prudent discount practice manual (**PD Practice Manual**). The PD Practice Manual is not binding on Transpower but Transpower must provide details of any departures from the PD Practice Manual. The PD Practice Manual will provide technical information and explanations on the approaches and methodologies that Transpower may adopt when assessing a prudent discount application in accordance with the TPM.

22. **Criteria for IBPDs:** For IBPD applications, Transpower must assess whether the alternative project (i) would provide the same or substantially similar level of service, (ii) is technically

[8] References document #67 Letter from EA: Checkpoint 2B resubmission

[9] Transpower is not able to bind an independent expert in relation to timeframe for completing any independent review.

feasible (including from a consenting perspective), (iii) is operationally feasible; (iv) is consistent with good electricity industry practice (**GEIP**), and (v) is commercially viable.

23. **Criteria for SACPDs:** For SACPD applications, Transpower must assess whether the alternative project (i) is an efficient stand-alone investment that would provide the same or substantially similar level of service, (ii) is technically feasible (but not necessarily from a consenting perspective), (iii) is operationally feasible; (iv) is consistent with GEIP, and (v) is commercially viable.

24. **Criteria for SACPD alternative projects:** An efficient stand-alone investment is determined using brownfields (or scorched node) optimisation, consistent with previous Commerce Commission Part 4 Commerce Act Optimised Deprival Value (**ODV**) precedent, and Telecommunications Act copper Unbundled Bitstream (**UBA**) and Unbundled Copper Local Loop (**UCLL**) Total Service Long-Run Incremental Cost (**TSLRIC**) pricing precedent.

25. **Alternative projects need not be transmission investments:** The alternative project used for IBPDs and SACPDs is not limited to transmission investments, and may include transmission alternatives such as generation, subject to meeting the above criteria.

26. **Funding:** For the purposes of recovering a prudent discount that is granted to a recipient, the prudent discount is assumed to relate to the relevant BBIs of which the recipient is a beneficiary in proportion to the size of the recipient's existing BBCs for those BBIs relative to its total existing BBCs for those BBIs plus, where the prudent discount includes a discount to the recipient's residual charge and/or connection charges, the recipient customer's residual charge. The prudent discount is recovered accordingly from the beneficiaries of the relevant BBIs of which the recipient is a beneficiary plus, where applicable, load customers.

5 Approach to SACPD

27. The Guidelines require that the SACPD cap a customer's transmission charges at the "efficient standalone cost of the transmission line services a designated transmission customer receives based on the hypothetical investment that would be required to supply solely that designated transmission customer".[10]

5.1 Efficient stand-alone cost

28. A key issue is how efficient stand-alone cost will be defined and determined, which is not prescribed by the Guidelines. The proposed TPM includes three definitions relevant to determining efficient stand-alone cost:

> **alternative project** means—
>
> …
>
> (b) for a **customer's** application for a **stand-alone cost prudent discount**, an investment in the **grid** or a **transmission alternative** by an efficient **transmission services** provider that, if implemented, would provide **transmission services** in substitution for all of the **transmission services** the **customer** currently receives from **interconnection assets**

[10] Reference document #4 Guidelines, clause 47(a).

alternative project costs has the meaning in clause 115.

...

115 Calculation of Alternative Project Costs

(1) The **alternative project costs** for an **alternative project** are the capital, operating, maintenance and overhead costs of the **alternative project** for the application, as would be incurred by:

...

(b) an efficient **transmission services** provider, in the case of **a stand-alone cost prudent discount**.

(2) For the purposes of calculating the **alternative project costs**, the value of any increase or decrease in **electrical** losses that would result from the **alternative project** must be included as an operating cost of the **alternative project** (with a decrease being treated as a negative cost).

efficient stand-alone investment has the meaning in clause 132.

...

132 Assessment of Efficient Stand-alone Investment

(1) An **efficient stand-alone investment** is an investment in **grid** or a **transmission alternative** an efficient **transmission services** provider would make to supply **transmission services** solely to the **customer** who has applied for a stand-alone cost prudent discount, assessed by—

(a) using the existing **grid** and the **customer**'s existing **points of connection** to the **grid** as a starting point; and

(b) holding **connection assets** constant; and

(c) applying optimisation tests to **interconnection assets** to identify, in the single-**customer** hypothetical, stranded **interconnection assets**, excess capacity in **interconnection assets** and other **interconnection asset** over-engineering.

(2) An **efficient stand-alone investment** does not need to be in the same location or follow the same route as the existing **grid**.

29. The alternative project for a SACPD application must be an efficient stand-alone investment (clause 131(1)(a)). In that case, the total of the alternative project costs is the efficient stand-alone cost, which is used to assess whether or not a prudent discount may be granted to the applicant.

30. The key features of the above definitions with respect to efficient stand-alone cost are as follows:

30.1 The alternative project must provide transmission services in substitution for *all* of the transmission services the applicant customer receives from interconnection assets. We interpret clauses (vi)(a) and 47 of the Guidelines as not permitting an alternative project that would only provide partial substitution. The interconnection assets restriction comes from the reference to the "interconnected grid" in clause (vi)(a) of the Guidelines.

30.2 The alternative project does not need to be capable of supplying any customer other than the applicant customer. This comes from the reference in clause 47(a) of the

Guidelines to the hypothetical investment (alternative project) supplying "solely that designated transmission customer."

30.3 The definition of efficient stand-alone investment uses a high level "brownfields" efficiency standard, which is principles-based and non-prescriptive. The approach is to optimise (adjust) the existing (actual) grid to reflect the hypothetical supply of grid services to a single customer only. Connection assets are held constant, consistent with the alternative project only substituting for transmission services provided by the interconnected grid.

5.2 Scope of alternative project

31. In our PDP consultation paper, we proposed to restrict alternative projects for SACPD applications to transmission investments.[11] This proposal was based on the use of the defined term "transmission lines services" in clause (vi)(a) of the Guidelines, which does not explicitly include transmission alternatives.[12]

32. We received submissions as part of our consultation process that alternative projects for SACPD applications should not be limited to transmission investments.

33. Having considered further, including taking into account the submissions we received, our proposal is to allow transmission alternatives as alternative projects for SACPD applications (note, transmission alternatives are also allowed as transmission alternatives for IBPD applications). This is consistent with the Commerce Commission's regulation of Transpower under Part 4 of the Commerce Act 1986, which in fact covers our investments in transmission alternatives as "electricity lines services".

34. We also note this proposal is consistent with:

34.1 clause 47(b) of the Guidelines, which refers to "the cost of supplying transmission services", not "the cost of supplying transmission lines services"; and

34.2 Clause 9 of the Guidelines, which requires the TPM's treatment of transmission alternatives to be consistent with its treatment of the transmission investments the alternatives seek to avoid.

35. We have accordingly included "an investment in the grid *or a transmission alternative*" in the part of the definition of "alternative project" in the proposed TPM that relates to SACPDs and made corresponding changes elsewhere.

5.3 Brownfields approach

36. The Guidelines do not specify the efficiency standard for a SACPD. Three obvious options include Transpower's actual efficiency level, a brownfields efficiency standard or a

---

11 Reference document #22 Prudent Discount Policy consultation paper paragraph 133. This position was also reflected in our summary and response (reference document # 38 Prudent Discount Policy consultation: Summary and Response

12 The definition of "transmission lines services" ultimately tracks to paragraph (a) of the definition of "electricity lines services" in section 54C(1) of the Commerce Act 1986: "the conveyance of electricity by line in New Zealand".

greenfields[13] efficiency standard. We note the Authority did not progress an earlier proposal to mandate that SACPDs be based on the efficient greenfields stand-alone cost of supply.[14]

37. The Commerce Commission adopted a brownfields efficiency standard in the Optimised Deprival Valuation (ODV) Handbooks that previously applied to the valuation of the grid and electricity distribution networks.[15]

38. The Commerce Commission also adopted a brownfields approach more recently when it applied total service long run incremental cost (**TSLRIC**) modelling to Chorus' unbundled bitstream access (**UBA**) and unbundled copper local loop (**UCLL**) copper network services.[13] Brownfields versus greenfields was discussed and debated extensively during the Commerce Commission's UBA and UCLL pricing determination. We have taken account of this in our consideration of the appropriate approach for SACPDs.

39. For example, the Commerce Commission has said a brownfields (or "scorched node") approach:[13]

> is appropriate and provides a reasonable approximation of the forward-looking efficient costs …
>
> is consistent with how other regulators have approached similar price tasks.
>
> has significant practical advantages as it corresponds to a more realistic efficiency standard and acknowledges (to a degree) real-world investment decisions made by the network operator, while allowing for optimisation where efficiencies can be identified. It also allows for a greater degree of flexibility in approach.

40. For these reasons, our initial thinking in the PDP consultation paper was that it would be appropriate to adopt a brownfields efficiency standard for the SACPD.

41. We also proposed that the brownfields efficiency standard be specified at a principles-level rather than using prescriptive rules. More detailed assumptions and methodologies used to assess efficient stand-alone investments may be developed over-time and recorded in a PD Practice Manual (see Section 7 below).

42. Submitters largely agreed that the SACPD should adopt the brownfields efficiency standard we proposed. No submitter advocated for a greenfields approach.

43. We also received submissions supporting:

    43.1 our reliance on telecommunications precedent for determining the efficiency standard, which reinforced the efficacy of a brownfields approach; and

    43.2 a principles-based and non-prescriptive approach to determining efficient stand-alone cost.

44. Our proposal is to adopt a brownfields efficiency standard for the SACPD. We have not been able to identify any justification specific to transmission pricing or electricity for reaching an

---

13 The Commerce Commission defines a greenfields (or "scorched earth") approach as "the hypothetical efficient operator builds its new network from scratch without being constrained by [the regulated supplier's] legacy decisions." (Commerce Commission, Final pricing review determination for Chorus' unbundled copper local loop service [2015] NCC 37, footnote 379). In contrast, a brownfields approach retains some part of the existing network.

14 Reference document #2 2019 Issues paper: Supplementary consultation, question 6.

15 Commerce Commission, Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Lines Businesses, 30 August 2004. The ODV methodology applied to Transpower until 30 June 2006. At that time a change was made to retain ODV values for assets existing at 30 June 2006 and adopt a depreciated historic cost valuation methodology with no optimisation requirements for new assets.

alternative conclusion to that of the Commerce Commission as the expert regulator on these matters.

45. The principles we propose for determining an efficient stand-alone investment, and therefore efficient stand-alone cost, are in clause 132 of the TPM drafting. One of the principles is that an efficient stand-alone investment does not need to be in the same location or follow the same route as the existing grid.

5.4 Supporting overhead costs

46. Our proposal is that the stand-alone cost of providing a service to a single customer would include supporting overhead costs (the definition of “alternative project costs” in the proposed TPM includes overhead costs). These costs may be lower than Transpower’s actual overhead costs reflecting that a smaller business only serving one customer may have lower overheads.

47. We received submissions seeking assurance the SACPD will be applied on a genuine stand-alone cost basis, inclusive of supporting overhead costs, and costs will not be determined on an incremental cost basis. We agree.

48. An incremental cost approach to overheads (shared and common costs) would not be consistent with a stand-alone cost approach.

5.5 Equivalence, feasibility and commercial viability assessment

49. Clause 131(1)(a) of the TPM drafting provides that the alternative project for a SACPD application must provide a level of service equivalent to the transmission services the applicant currently receives.[16]

50. Consistent with the criteria for IBPDs, the TPM drafting also requires the alternative project to be technically and operationally feasible, otherwise consistent with good electricity industry practice (**GEIP**), and commercially viable (clause 131(1)(b) to (e)). However, a key difference for SACPDs is that it is not necessary for it to be feasible to obtain all resource consents and property rights that would be required for the alternative project (clause 131(2)).[17]

51. We received submissions about ensuring the alternative project provides a genuinely equivalent service. On the other hand, we received a submission from NZ Steel that: “The PDP provisions should provide for those who are willing and able to accept a [lesser] supply for a [lesser] cost.”

52. We consider that the appropriate approach is that the alternative project provide an equivalent level of service and reflect GEIP, and this is the approach that we have adopted in our proposal.

53. We do not agree with the alternative perspective put forward in NZ Steel’s submission, which would introduce subjectivity and create incentives for an applicant to overstate their willingness to accept a lower quality service. It should be noted that while the applicant

[16] This is our interpretation of the “equivalent value” requirement in clause 47(b) of the Guidelines. Equivalency of service is also an existing requirement for IBPDs (clause 38(1)(c) of the current TPM).

[17] As it will always be necessary to determine the alternative project costs for a SACPD (the efficient stand-alone cost), clause 74(2) provides for the cost of obtaining infeasible resource consents and property rights to be estimated based on the cost of obtaining equivalent resource consents and property rights that are feasible to obtain.

could claim it does not need or want the service quality it is currently getting, the prudent discount would not result in any change in the actual service quality the applicant receives.

54. We consider the "cost of supplying transmission services that are of equivalent value to the customer" should be determined objectively, by reference to the actual service the applicant receives, not subjectively from the applicant's perspective. We consider the principles in clause 1(b) and (c) of the Guidelines support this approach.

5.6 Impact of SACPD on transmission charges

55. We propose the effect of a SACPD will be to reduce all of a discount recipient's BBCs to zero (clause 134 of the proposed TPM). This is consistent with the alternative project substituting for all transmission services the recipient receives from the interconnected grid, i.e. that deliver positive net private benefits to the recipient.

56. We do not propose to adjust the discount recipient's residual charge. Although the recipient's residual charge may recover the costs of some pre-2019 investments in the interconnected grid the customer receives positive net private benefits from, it is not practicable to determine how much of the recipient's residual charge (if any) relates to those costs. We consider any attempt to do so would involve excessive administrative burden in pursuit of (probably false) precision, and so be inconsistent with the principle in clause 1(b) of the Guidelines.

57. We do not propose to adjust the recipient's connection charges either, as those charges do not relate to the costs of the interconnected grid.

58. Our proposal not to adjust the recipient's residual charge has implications for how the amount of a SACPD is recovered because no part of it will be attributable to a reduction in the recipient's residual charge. This is discussed further in Section 9.

5.7 SACPD agreements

59. Our proposal is that the term of a prudent discount agreement for a SACPD be 15 years (paragraph (b)(ii) of the definition of "prudent discount calculation period" and clause 119(3) of the TPM drafting), and present value calculations for SACPDs should be carried out over the same period. This period is the same as the current maximum term for an IBPD, which we do not consider needs to be changed. It also reflects the maximum period the PDP modelling will apply for. We consider 15 years to be an appropriate term given the potential for conditions in the power system to change in ways not anticipated when a prudent discount application is approved. There would be no impediment to a customer applying to renew its prudent discount agreement before it expires.

60. Submitters who commented generally (although not unanimously) agreed that the term of a prudent discount agreement for a SACPD should be 15 years.

61. The TPM drafting provides a right for the customer to terminate a prudent discount agreement for a SACPD at the start of a pricing year by notifying Transpower at least six months in advance (clause 119(2)(d)). We consider this is appropriate given the entirely hypothetical nature of the alternative project for a SACPD[18] and the potential for the

[18] In contrast, an IBPD would be granted on the basis the customer would build the alternative project otherwise, in which case the customer would be stuck with the alternative project for at least the term of the prudent discount agreement.

customer to be better off without the prudent discount agreement at some point during its term. The six months' notice period is so we have time to factor the termination of the prudent discount agreement into our annual pricing process and avoid the need to wash-up transmission charges for the previous pricing year.

5.8 Threshold for SACPDs

62. We received submissions advocating a *"high bar"* for successful SACPD applications. We agree the bar should be high, given that other transmission customers would have to fund the SACPD on the basis of a hypothetical, and potentially infeasible, project e.g. it could include transmission lines through National Parks.

63. We consider our proposals – consistent with the Guidelines – result in an appropriately high bar for a SACPD to be granted.

6 Process and administrative changes

64. Our proposal includes a number of changes to the process and administrative arrangements for prudent discount applications. These changes would apply to both IBPDs and SACPDs.

65. Some of these changes address clause 48 of the Guidelines (practical ways to facilitate greater transparency on the matter of prudent discounts).

66. Our proposed process and administrative changes were generally considered appropriate by submitters.

6.1 Application fees

67. Our proposal is for fees to be payable for applications under the TPM, including prudent discount and reassignment applications (clause 16 of the TPM drafting). Application fees would be published on Transpower's website and would have to be reasonable having regard to our expected costs of processing the relevant application (definition of "application fee" and clause 16(3)).

68. This is consistent with the Commerce Commission's approach to customised price-quality path (**CPP**) applications by regulated suppliers operating under default price-quality paths, which is enabled by sections 53Q(2)(c) and 53Y of the Commerce Act 1986. The standard application fee for a CPP proposal is $20,000, which is intended as a part payment for the Commerce Commission's costs.[19]

69. In our PDP consultation paper we noted the Authority's expectation that our costs for processing prudent discount applications could be in the order of $100,000.[20] Some submitters questioned the level of application fee that should attach to a prudent discount application (including whether the application fee should be split with only a modest part payable for the initial screening of applications).

[19] Commerce Commission *How do businesses apply for a CPP*

[20] Reference document #3 2020 decision, paragraph 12.33, footnote 218.

70. Having considered the submissions received, our current thinking is to split the application fee and require the larger part to be paid only if the application proceeds to detailed assessment.

71. The amount and structure of application fees is not something we need to resolve as part of our proposal but we have signalled in clause 16(3) of the TPM drafting some potential approaches to application fees, including that they may be refundable or based on actual cost.

72. Our proposal is that an applicant's failure to pay an application fee (or comply with other requirements) would be grounds to suspend our assessment of the application or reject it (clause 16(1) of the TPM drafting). We also propose to be able to reject a prudent discount application if it is substantially similar to a previous rejected application and circumstances have not changed materially (clause 113(1)(b)).

6.2 Application requirements[21]

73. Our proposal is that we would publish the detailed content requirements for applications under the TPM on our website, as an alternative to including them in the TPM itself (definition of "application requirements" and clause 16(4) of the TPM drafting). Currently, the content requirements for IBPD applications are in Appendix C of the TPM.

74. We consider this is appropriate so that a TPM change is not required whenever Transpower changes the content requirements for applications. This flexibility is likely to be particularly useful for new features of the TPM, such as SACPDs and reassignment.

6.3 Independent verification

75. Our proposal is that prudent discount applications would be required to be independently verified by one or more relevant experts approved by Transpower (definition of "independent verification" and clause 112(2)(d) of the proposed TPM). It would be the applicant's responsibility to arrange the independent verification, which would be submitted with the application.

76. We consider independent verification has been a useful and successful mechanism for proposals under Part 4 of the Commerce Act 1986 for both Transpower and CPP applicants.[22] The Commerce Commission intends to expand independent verification to its regulation of fibre fixed line access services under Part 6 of the Telecommunications Act 2001.

77. Submitters agree.

78. On the issue of who would verify which parties qualify as a relevant expert, we do not consider there is any reason why Transpower is not capable of approving the independent verifier or would be conflicted in doing so.

---

21 Transpower notes that it will assess all applications that it receives as soon as is as reasonably practicable, but given the potential complexity of applications, Transpower does not consider that it is able to include a fixed timeframe for assessing any potential application in the TPM.

22 The approach is also being adopted for Chorus' fibre network business under Part 6 Telecommunications Act, which are based on the Part 4 Commerce Act arrangements that apply to Transpower.

6.4 Publication and consultation

79. Our proposal is that we would:

    79.1 publish prudent discount applications and information provided in support of them (clause 113(3) of the proposed TPM);

    79.2 consult on Transpower's draft decision on a prudent discount application (clause 117); and

    79.3 publish prudent discount decisions, including final prudent discount agreements (not just selected information from them, as is currently the case) (clause 121).

80. We consider our obligation to publish applications and prudent discount agreements should be subject to a discretion to withhold any information (other than the core elements of the prudent discount) if Transpower considers publishing the information would commercially disadvantage a benefitting customer or other person in a material manner (clause 122 of the proposed TPM).

81. We consider consultation should not be necessary if Transpower decides to reject a prudent discount application during the screening process because the applicant or application does not comply, or has not complied, with the application requirements in the TPM, or the application is substantially the same as one that has already been rejected and there has not been a material change in circumstances (clause 113(1)(b) of the proposed TPM).

82. No submitter raised any objection to our proposed approach to publication and consultation.

83. Our proposal is to consult on all draft decisions on prudent discount applications, including any decision to reject other than for screening reasons (clauses 113(2) and 117 of the proposed TPM).

84. We consider the introduction of these new publication and consultation requirements to the PDP is appropriate as non-applicant customers will have a financial interest in the outcome of a prudent discount application to the extent they will fund the prudent discount if the application is approved. Consultation will also provide extra scrutiny of prudent discount applications and decisions. This is consistent with the Commerce Commission's process for CPP applications under Part 4 of the Commerce Act 1986 and our approach to pricing matters generally.

7 Prudent discount practice manual

85. Our proposal is that the TPM would provide us with the ability to publish a non-binding PD Practice Manual. The fundamental and structural elements that Transpower will need to take account of when assessing a prudent discount application are included in the proposed TPM. The PD Practice Manual could contain a set of assumptions and methodologies that we may use to assess prudent discount applications under the TPM (clause 123 of the proposed TPM). The PD Practice Manual would be a living document, updated from time to time. This is the same as the preliminary proposal submitted to Checkpoint 2.

86. The efficacy of developing and publishing a prudent discount practice manual may depend on the number of prudent discount applications we receive (or expect to receive). In any

event, we think it would be advantageous to have the option of developing and publishing the practice manual.

87. The prudent discount practice manual would not be part of the TPM and it would not be a breach of the TPM for Transpower to depart from it; however, the contents of the practice manual must not be inconsistent with the TPM or any other provision of the Code (clause 123(2) of the proposed TPM). We consider the PD Practice Manual is a potentially valuable resource for both Transpower and applicants to keep a record of the more detailed assumptions and methodologies that can be expected to be applied to prudent discount applications.

88. There was strong support from submitters for our proposal to develop a prudent discount practice manual.

89. We received submissions asking for more detail about how efficient stand-alone cost would be determined in practice and for practical worked examples for the SACPD. We consider this would be appropriate content for the PD Practice Manual and will take this into account as we develop the practice manual.

90. As it would not be part of the TPM, the practice manual could not override our obligation to comply with the TPM (or the Code generally). However, we are cognisant of the need to adopt a transparent approach to departures from the manual, and have included in clause 121(c) of the proposed TPM an obligation on Transpower to inform the applicant of any material departures from the manual when we notify the outcome of the application, including the reasons for the departures. We would also be required to consult on any such departures under clause 117(2)(a) of the proposed TPM.

91. The Authority's provided feedback on our Checkpoint 2 submission as follows:

> Limiting discretion is important for the PDP, as otherwise there is a risk it could become a subsidy. The Authority's view is that structural and fundamental aspects of the methodology need to be in the proposed TPM rather than in other documents. We are also concerned about the need to provide certainty for stakeholders. If the detail of the PDP methodology is included in a PD Manual, we want to better understand Transpower's proposal for consultation, publication and future revisions of any manual – essentially its proposed balance between regulatory certainty and a flexible approach. The Authority requests that Transpower consider what options may be available that would limit the need for Transpower to exercise discretion (for example, approval rights for the Authority over the manual and for subsequent amendments to it) to ensure ongoing consistency with the guidelines and statutory objective. (We request also that Transpower consider this issue with respect to the Assumptions book for the benefit- based charge and any other manuals outside the TPM that it may be contemplating.)[23]

92. The balance of this section provides further information to inform the Authority's consideration of our prudent discount manual proposal, consistent with our Checkpoint 2 resubmission response to the Authority's feedback.

[23] Reference document #56 Letter from EA: Checkpoint 2B submission, paragraph B66.

7.1 Contents of PD Practice Manual

93. We agree with the Authority that *"structural and fundamental aspects of the [prudent discount] methodology need to be in the proposed TPM"*. The TPM drafting has been prepared, and further refined, to achieve this outcome. We consider the TPM drafting contains all structural and fundamental aspects Transpower will need to take account of when assessing a prudent discount application. For example, all key tests and thresholds for obtaining a prudent discount are expressly incorporated. Specifically:

    93.1 the commercial viability test is in clause 116;

    93.2 the equivalence, feasibility and GEIP tests are in clauses 126 and 131;

    93.3 the inefficiency test for inefficient bypass prudent discounts (**IBPDs**) is in clause 127; and

    93.4 the principles-based definition of "efficient stand-alone investment" for stand-alone cost prudent discounts (**SACPDs**) is in clause 132.

94. In our view, the TPM drafting contains a reasonable level of prescription, and a level that is equivalent to or exceeds the level of prescription of the prudent discount drafting in the current TPM. For example, the equivalence and feasibility tests are more prescribed than in the current TPM and our discretion to choose the discount rate has been reduced, consistent with clause 1(b)(iii) of the Guidelines.

95. The purpose of the PD Practice Manual (clause 123 of the TPM drafting) is to support the PDP by providing a set of technical assumptions and methodologies that may be used by Transpower to assess applications for prudent discounts under the new TPM. The content of the PD Practice Manual would be assumptions and methodologies that may change over time e.g. asset replacement cost and type. This could include matters such as the cost of consenting for different types of alternative project and procurement costs for equipment. Given the nature of the assumptions and methodologies that may be included in the PD Practice Manual, we consider it is not practicable or appropriate to include them in the new TPM or to mandate that they be applied.

96. As we gain experience with the new PDP and assess individual applications under it, we are likely to discover technical assumptions and methodologies that may be relevant to prudent discount applications, particularly as the industry changes and evolves over time. We would expect to record these assumptions and methodologies in the PD Practice Manual. It may not be practicable or constructive to incorporate them in the TPM (or update them in the TPM when they change) due to the process requirements for re-opening the TPM, which include at least a 12-month gap between operational reviews under clause 12.85 of the Code.

97. To the extent any technical assumption or methodology in the PD Practice Manual proves resilient over time, such that it could be considered to form part of the PDP rules, it could be added to the TPM later as part of an Operational Review. At this time, we have not established or identified any such technical assumptions or methodologies that could be included in the TPM.

98. Importantly, the contents of the PD Practice Manual will need to be consistent with, and could not over-ride the requirements of, the TPM or anything else in the Code (clause 123(2) of the TPM drafting) and will be subject to various checks and balances as outlined below. This will ensure *"ongoing consistency with the guidelines and statutory objective"*.

99. The Australian Energy Market Commission has published a Rule Drafting Philosophy to guide it in making rules for the Australian National Energy Market.[24] The Rule Drafting Philosophy refers to finding an appropriate balance between prescription and principle in the rules and supports the use of guidelines outside the rules where appropriate. We consider the following extract from the Rule Drafting Philosophy captures the reasons why the PD Practice Manual is appropriate:[25]

> It may be appropriate for Rules to provide for guidelines or procedures in the following circumstances:
>
> - matters where there may be several acceptable means for regulated parties to achieve the particular outcome specified in the Rules
> - matters where industry experience may develop over time
> - matters which require frequent adaptation to changes in such things as technology and communications
> - matters where detailed procedural matters can be left to the relevant regulatory entity to develop in consultation with industry
> - matters that are suited to industry standards or processes developed or applied by a body more closely associated with the management and operations of an industry, but only to the extent that a conflict of interest would not likely arise.

7.2 Process requirements for PD Practice Manual

100. The TPM drafting requires us to:

100.1 consult with customers on the PD Practice Manual and any update to it before publication (subject to limited exceptions that mirror those that apply to the Authority's consultation on Code amendments under section 39(3) of the Electricity Industry Act 2010) (clause 123(3) and (4));

100.2 consult with customers on any proposed material departures from the assumptions and methodologies in the PD Practice Manual (clause 117), which are also subject to review by an independent expert (clause 118); and

100.3 publish details of any material departures from the assumptions and methodologies in the PD Practice Manual when we make a final decision (clause 121).

101. These process requirements are designed to ensure transparency, accountability and stakeholder involvement. If a customer or other person considers the PD Practice Manual, or our application or non-application of the assumptions and methodologies in it, is inconsistent with the TPM or anything else in the Code, the normal Code breach processes will apply (as well as the independent expert process in some cases). However, we do not expect applying an assumption or methodology from the PD Practice Manual is likely to yield outcomes inconsistent with the TPM or the Code, given they will be limited to technical matters only.

102. We note the PD Practice Manual (or something like it) will likely exist for our internal operational and decision-making purposes whether or not it is referred to in the TPM. This will be to ensure consistency in our decision-making and help prospective prudent discount

[24] AEMC, Rule Drafting Philosophy, 8 October 2020.
[25] AEMC, Rule Drafting Philosophy, 8 October 2020, page 10.

applicants. Referencing the PD Practice Manual in the TPM allows consultation and publication obligations to attach to it (as outlined above), which will help safeguard transparency and benefit all stakeholders.

103. We have considered the option of the Authority having approval rights over the PD Practice Manual. On balance, we do not consider Authority approval would be appropriate given the technical content of the manual, which we consider is best developed with industry through the consultation process. We note also that the Authority has previously declined to be involved in the assessment of prudent discount applications (which we had suggested for SACPD applications).[26]

8 Analytical and commercial changes

104. We propose a number of analytical and commercial changes to the existing PDP arrangements. To the extent applicable, and in the interests of consistency, these changes would apply to both IBPDs and SACPDs under the new PDP.

8.1 Treatment of electrical losses

105. Our proposal is that changes in electrical losses would be factored into the costs of an alternative project (clause 115(2) of the proposed TPM).

106. Under Appendix C of the current TPM, an applicant for a prudent discount must provide information about electrical losses, but the current PDP does not address how that information is factored into the criteria for a prudent discount (and neither do the Guidelines).

107. The published summary information for the Waipori and Matahina/Aniwhenua prudent discounts[27] says additional electrical losses were factored in as costs of the alternative projects (specifically, operating costs). We consider this is the correct approach.

108. We also consider allowance should be made for alternative projects that would reduce electrical losses (treated as a negative cost).

109. We received submissions in support of this approach. As compared to the position on which we consulted, the TPM drafting omits the "material" qualifier as we agree any change in electrical losses reasonably able to be calculated or estimated should be taken into account.

8.2 Treatment of benefitting customers

110. The current PDP does not consistently acknowledge the possibility that an IBPD application may have more than one benefitting customer.

111. Our proposal is that all benefitting customers for an IBPD (being those customers named in the application) would be involved in the application, including by being factored into the tests for commercial viability and inefficiency (definition of "benefitting customer" and clause 125 of the TPM drafting).

[26] Reference document #3 2020 Decision, paragraph 12.39-12.40
[27] See footnote 3.

112. This was the approach for the Waipori and Matahina/Aniwhenua prudent discounts (although the current PDP does not expressly provide for it). We consider it to be the correct approach.

113. Submitters generally agreed all benefitting customers for an IBPD should be involved in the application.[28]

8.3 Discount rate for present value calculations

114. Our proposal is that the discount rate for the tests for commercial viability and inefficiency, and for the calculation of the annuity, would be:

 114.1 for an IBPD, the applicant customer's weighted average cost of capital (**WACC**). For a distributor, this would be the distributor information disclosure WACC at the time of the prudent discount application, as determined by the Commerce Commission under Part 4 of the Commerce Act 1986. If the customer is not a distributor, WACC would be determined by Transpower. We consider it is appropriate to use a customer-related discount rate for IBPDs because the analysis is based on costs to the customer; [29] or

 114.2 for a SACPD, Transpower's information disclosure WACC at the time of the prudent discount application, as determined by the Commerce Commission under Part 4 of the Commerce Act 1986. We consider it appropriate to use a Transpower-related discount rate for SACPDs because the analysis is based on costs incurred by an efficient transmission services provider (definition of "prudent discount discount rate" and clauses 116(2), 120 and 127(3) of the TPM drafting).

115. We consider these discount rates are more appropriate than a fixed 7% default rate,[30] a rate determined by the Authority or a generic *"commercial discount rate"*, which are referred to in the current PDP.[31] The current 7% rate would, for example, be excessive based on prevailing interest rates,

116. Submitters who commented generally agreed Transpower's WACC should be used as the discount rate for SACPD applications. There were differing views about the appropriate discount rate for IBPD applications.

117. We propose that a regulated WACC should be used where possible, so (as noted above) we are now proposing to use a regulated WACC for all distributors, including those who are not subject to price-quality regulation. However, for non-regulated applicants we consider we will need to retain a discretion to determine the appropriate WACC. That determination, and every other determination we make under the TPM, would be subject to the constraints in clause 13 of the TPM drafting.[32]

118. Another difference between our proposal and our initial thinking in the PDP consultation paper is that we now propose to use annually-determined information disclosure WACCs for the discount rates rather than price-quality WACCs, which are determined for entire

---

[28] For example, Trustpower submitted *"We agree that all benefiting customers from an IBPD should be involved in the application, including by being factored into the tests for commercial viability and inefficiency"*.

[29] "Customer WACC" was used for the Waipori and Matahina/Aniwhenua prudent discounts. See footnote 2.

[30] A 7% discount rate would be very high given current interest rates.

[31] Clauses 39(4) and 41(1)(a) of the current TPM.

[32] We expect the application requirements for IBPDs will require a non-regulated applicant to provide information and evidence about what its WACC is. The matter may also be addressed in the prudent discount practice manual.

regulatory control periods. We consider this will make for more accurate calculations, especially for prudent discount applications that are made in the later years of a regulatory control period e.g. the cost of the alternative project if it went ahead would be based on interest rates/WACC available at that time, not historic interest rates/WACC that is no longer accessible. The Information Disclosure WACC may be less or higher than the price control WACC (it is presently lower).

8.4 Commercial viability test

119. Our proposal is that the commercial viability test (clause 116 of the TPM drafting) would be:

119.1 based on present value, for consistency with the other calculations in the PDP; and

119.2 simplified to alternative project costs being materially less than avoided transmission charges.[33]

120. We consider these changes to be appropriate for consistency and simplicity. We consider the introduction of a materiality threshold to be appropriate because a prudent Board would be unlikely to take the risk of investing in an alternative project if the gains were forecast to be marginal only.

8.5 GEIP criterion

121. As well as being technically and operationally feasible, our proposal is that any alternative project would be required to be consistent with GEIP (definition of "GEIP" and clauses 126(d) and 131(1)(d) of the TPM drafting).

122. We consider this change would ensure an appropriate engineering standard, beyond mere feasibility, is factored into the assessment of alternative projects. For example, an alternative project that is considered to be unsafe or unreasonably experimental should not be the basis for a prudent discount.

8.6 Levelised annuity

123. Our proposal is that the annuity under a prudent discount agreement would be required to be levelised (clause 120 of the TPM drafting).

124. We consider this change is appropriate for administrative convenience in setting transmission charges. It reflects the approach for the Waipori and Matahina/Aniwhenua prudent discounts.

8.7 Commencement of prudent discount agreement

125. Our proposal is that the commencement of a prudent discount agreement would be required to coincide with the start of a pricing year beginning at least six months after the prudent discount agreement is executed (clause 119(3) of the TPM drafting). For SACPDs, as the alternative project is entirely hypothetical, there would be no further potential delay based on the time it would take to build the alternative project (as there is for an IBPD).

[33] The formulation of the commercial viability test in clause 38(1)(c) of the current TPM effectively has unavoided transmission charges as a constant on each side of the inequality.

126. The six-month lead time is necessary, so we have time to factor the prudent discount into our annual pricing process[34] and avoid the need to wash-up transmission charges for the previous pricing year.

8.8 Conditional approvals and termination

127. Our proposal is that we would be able to approve a prudent discount application subject to reasonable conditions (clause 118(1)(b) of the proposed TPM). We would have a right to terminate the prudent discount agreement if any of the conditions of our approval is not, or ceases to be, satisfied (clause 119(2)(c)).

128. We consider these changes are appropriate to address a concern raised in response to the 2019 Issues Paper:[35]

> Some parties noted that the conditions that applied when the prudent discount was agreed may not be enduring. Trustpower observed that a discount may be provided on the basis that the customer is able to use an alternative energy source (such as gas) but the price of that alternative may later increase, suggesting that the discount should be revised.

8.9 Two clarifications

129. Although not a change to the current PDP, our proposal gives greater prominence to the criterion that the alternative project for an IBPD must provide the same or a similar level of service as the grid assets being bypassed (clause 126(a)).[36]

130. The proposed TPM also expressly states the requirement that the alternative project be feasible from a property and consenting perspective, as part of the technical feasibility criterion for an IBPD (clause 126(b)).[37]

9 Funding Prudent Discounts

131. The amount of a prudent discount is part of Transpower's recoverable revenue. There is a question as to which group of customers the prudent discount should be recovered from under the TPM.

132. The current PDP does not address this question directly. The effect is that prudent discounts are recovered from offtake customers only, through the interconnection charge.

9.1 Guidelines requirements and Authority intent

133. The Guidelines do not directly address prudent discount funding.

134. Clause 15 of the Guidelines requires that the full covered cost of a BBI must, except as provided for in clause 16, be recovered from the beneficiaries of that investment.

---

[34] Under clause 41.5(a) of the benchmark transmission agreement, we must give at least three months' notice of a change to transmission charges that will be effective at the start of a pricing year. Before we notify customers the new transmission charges need to be calculated, audited and approved by our Board.

[35] Reference document #3 2020 Decision, paragraph 12.9.

[36] In the current PDP this criterion is somewhat hidden at the end of clause 38(1)(c), which primarily relates to commercial viability.

[37] This requirement is relaxed for SACPDs in clause 74(2).

135. Clause 16 of the Guidelines provides an indication of what may have been intended for funding prudent discounts. Clause 16 includes a list of circumstances where a benefit-based charge may not recover the full covered cost of the relevant BBI. Prudent discounts are not in the list, which implies an intent that, to the extent a prudent discount relates to the cost of a BBI, the portion of the covered cost of that BBI that is no longer recoverable from the recipient customer should be recovered from the other beneficiaries of that investment in a manner consistent with clause 15 of the Guidelines.

136. However, the Authority's comments in its 2020 Decision about how prudent discounts would be recovered are potentially inconsistent with their exclusion from clause 16 and recovering prudent discounts through BBCs:

136.1 At paragraph 9.95 of its 2020 Decision, the Authority said, for both reassignments and prudent discounts, "the part of the cost of the investment no longer recovered by the benefit-based charge is spread across all load customers via the residual charge".

136.2 At paragraph 12.25 of its 2020 Decision, the Authority said it expects funding for prudent discounts to be *"spread across a large pool of customers."*

137. The Authority has also stated that part of its reasoning for reviewing transmission pricing and replacing the Guidelines is a concern that charging offtake customers only for interconnection investments results in a subsidy from load to generation.[38] A similar objection would apply to recovery of a prudent discount from load customers only.

9.2 Options

138. There are at least four options for recovering prudent discounts under the new TPM. We identified the first three options as part of our PDP consultation and option 4, subsequently, after reviewing submissions and Authority feedback:

138.1 **Option 1:** Full or partial recovery through benefit-based charges – This option would involve determining how much of a prudent discount relates to a particular benefit-based investment and allocating that part of the prudent discount to the other beneficiary customers for the investment. We consider that this option would be consistent with the Guidelines.

138.2 **Option 2:** Full recovery through residual charge - This option is similar to the status quo – prudent discounts would be recovered from load customers only, through the residual charge. We consider that this option would require a departure from clause 15 of the Guidelines with respect to the recovery of prudent discounts.

138.3 **Option 3:** Recovery from all customers – This option is to spread the funding for prudent discounts over all customers (other than the recipient of the prudent discount) in proportion to their total transmission charges or some subset of them. We consider that this option would require a departure from clause 15 of the Guidelines with respect to the recovery of prudent discounts.

[38] For example: *"The interconnection charge only applies to load, which means the cost of supplying interconnection services to generators is fully cross-subsidised by load"* (Authority, Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets: Working paper, 16 September 2014, paragraph 8.5(a).

138.4 **Option 4 (hybrid of options 1 and 3)**: The prudent discount is assumed to relate to the relevant BBIs in proportion to the size of the recipient's existing BBCs for those BBIs relative to its total existing BBCs for those BBIs plus residual charge. The prudent discount is recovered accordingly. We consider that this option would be consistent with the Guidelines.

9.3 Stakeholder perspectives

139. Funding was the PDP topic where there was the most diversity of views amongst submitters. We received support for each of the three options Transpower presented (option 4 was not consulted on):

139.1 **Option 1** (full or partial recovery through BBCs): ENA, MEUG, PowerNet, and Unison/Centralines.

139.2 **Option 2** (full recovery through the residual charge): Contact Energy, Meridian, Nova Energy (in cross-submission), Pioneer Energy, Refining NZ, and Trustpower.

139.3 **Option 3** (recovery from all customers): Counties Power, Network Waitaki, Northpower, Orion and Vector

9.4 Our proposal

140. In our preliminary proposal submitted to Checkpoint 2, we proposed that Option 3 be adopted. Option 3 would require Transpower to deviate from the Guidelines by way of a clause 2 departure.

141. The Authority's feedback on our Checkpoint 2 submission invited us to consider whether the approach we proposed (Option 3) "*risks undermining the Authority's intent to recover such residual costs from load customers via the residual charge.*" The Authority referenced the 2019 Issues paper, which "*explained that if residual costs are paid by generators the cost is eventually passed through to load via a higher wholesale price – which is more distortionary than if charged directly to load through a residual charge.*"

142. We subsequently revisited our analysis of the options for recovery of prudent discounts, taking into account the feedback we received from stakeholders and the Authority and based on our further consideration of the Guidelines, and in our Checkpoint 2B resubmission, we proposed that Option 4 be adopted.

143. We considered that Option 4 achieves best practicable compliance with clause 15 (and clause 8) of the Guidelines because:

143.1 the part of the prudent discount assumed to relate to the relevant BBIs is recovered from the other beneficiaries of those BBIs, in a manner that is consistent with their allocations;[39] and

[39] Option 4 overcomes the practical difficulty we identified with Option 1 at the Checkpoint 2 submission stage (identifying how much of a prudent discount relates to BBIs) by making a simplifying, and we consider reasonable, assumption, which is that the prudent discount is assumed to relate to the relevant BBIs in proportion to the size of the applicant customer's existing BBCs for those BBIs relative to its total existing BBCs for those BBIs plus (where applicable for the given prudent discount) residual charge payable by the recipient customer. We note that a prudent discount affecting a BBI inevitably means that the BBCs will not be allocated solely on the basis of positive net private benefit, but Option 4 means a reasonable proxy for the full covered cost of the BBI will still be recovered from the other beneficiaries.

143.2 it gives effect, consistent with the Guidelines, to the Authority's preference that any recoverable revenue not recovered from other transmission charges be recovered through the residual charge, without the need to rely on a departure from the Guidelines under clause 2. See paragraph 146 below in which we explain the portions of a prudent discount that would be assumed to relate to BBCs versus the residual.

144. In response to our Checkpoint 2B resubmission, the Authority commented in respect of proposed Option 4 that: "*The Authority considers that Transpower's new proposed approach to funding PDs is likely consistent with the Guidelines and is likely to be acceptable.*"

145. As described in Section 5.6 above, the prudent discount that is granted will determine the customers from which that prudent discount will be recovered. If the prudent discount includes a discount only to the recipient's benefit-based charges, then the prudent discount will be recovered only from the other beneficiaries of the relevant BBIs which the recipient is a beneficiary of. If the prudent discount includes a discount to both the recipient's benefit-based charges and residual charges or connection charges, then the prudent discount will be recovered from the other beneficiaries of the relevant BBIs which the recipient is a beneficiary of plus load customers. (Clause 135(1) of the proposed TPM, and see in particular "$RC_{recipient}$" in the relevant formula.)

146. By way of example:

146.1 In relation to the recovery of an IBPDs from a customer under our proposal, if a customer who pays $10 for a BBI and a residual charge of $30 obtained an IBPD of $20 (net of annuity) for an alternative project that bypassed the BBI, part of the prudent discount would be recovered by, effectively,[40] increasing other beneficiaries' BBCs for the BBI by a total amount equal to $20 x 10/(10 + 30) = $5. The remaining $15 of the prudent discount would be recovered by, effectively, increasing the residual charges of other load customers.

146.2 In relation to the recovery of a SACPD from a customer under our proposal, as a SACPD will not include any discount to the recipient's residual charge or connection charge (see Section 5.6 above), then we will set the residual charge aspect of the formula to 0. The effect of this is to allocate the prudent discount entirely to the affected BBIs of which the prudent discount recipient is a beneficiary. The prudent discount will then be recovered from the other beneficiaries of the relevant BBIs.

10 Consistency with the Guidelines

147. We consider our proposals for the PDP component of the TPM are fully compliant with the Guidelines. See the Guidelines compliance matrix attached to this paper.

[40] In the proposed TPM the increases are specified as charges in their own right - the BBI prudent discount recovery charge and residual prudent discount recovery charge.

Chapter 14: Additional Components

30 June 2021

Contents: Chapter 14

1 Introduction

1. This chapter summarises and explains the reasons for our decisions regarding additional components A, B, C, D, E, F and G provided for in the Guidelines, and whether to include each in our TPM proposal.

2 Requirements of the Guidelines

2. Clause (viii)(a) of the Guidelines states the intent for the additional components:

viii. Transpower must include each **additional component** in the **TPM** if doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**:

a. Adjustments to charges for 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 as to not unreasonably deter staged commissioning of **investments**.

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

c. Charges for **connection investments** to use a method substantially the same as for **benefit-based charges**. The purpose of this component is to allocate the charges for each **connection investment** in substantially the same way as the charges for each **benefit-based investment**.

d. Transitional **congestion charge**. The purpose of this component is to efficiently influence grid use for a limited transitional period, or if the Authority agrees, for a more extended period, when it is expected that the grid might become congested, if other means of controlling or influencing demand, including nodal pricing and administrative load control associated with scarcity pricing, 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** in the **interconnected grid**.

f. Allocation of **opex**. The purpose of this component is to attribute **opex** to the **connection investment** or **benefit-based investment** 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.

3. Clause 54 contains requirements for proposing 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. adjustments to charges for staged commissioning, as described in clause 55;
>
> b. charges for assets principally providing connection services, as described in clause 56;
>
> c. charges for **connection investments** to use a method substantially the same as for **benefit-based charges**, as described in clause 57;
>
> d. a transitional **congestion 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. allocation of **opex**, as described in clause 64; and
>
> g. a kvar charge, as described in clause 65.

4. Clauses 55 to 65 contain the requirements specific for each additional component:

> **Additional component A: adjustments to charges for staged commissioning**
>
> 55. This component must provide a method for Transpower, at its discretion, to adjust charges, change asset classification and/or use a hybrid asset classification so that in Transpower's reasonable opinion, the charges for a **connection asset** that will ultimately be an **interconnection asset** do not unreasonably deter the partial commissioning of the asset. The **benefit-based charge** must apply when the assets meet the definition of **interconnection assets** and must recover the present value of the **covered cost** of the **investment**, less any **connection charges** paid for it.
>
> **Additional component B: charges for assets principally providing connection services**
>
> 56. This component must provide a method to ensure that **connection assets** cannot be changed into **interconnection assets** by a person other than Transpower investing in other assets to create an interconnection loop.
>
> **Additional component C: charges for connection investments to use a method substantially the same as for benefit-based charges**
>
> 57. This component must provide for the method for determining the annual amount to be recovered for each new **connection investment** to align with the method for

determining the **annual benefit-based charge** for **post-2019 benefit-based investments**, notwithstanding the requirements of clauses 11 and 12.

Additional component D: transitional congestion charge

58. This component must provide a method for determining, in respect of a transitional **congestion 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 **congestion charge** may only apply in respect of those geographic areas, circuits or other circumstances in which Transpower expects, in its reasonable opinion, there is a significant likelihood of congestion occurring without a transitional **congestion charge**.

59. If Transpower determines to include a transitional **congestion 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 efficiently controlled by the other means, including nodal pricing and administrative load control associated with scarcity pricing.

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

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

    b. the **TPM** must include the process for phasing out the transitional **congestion charge**, including specifying the maximum transitional **congestion charge** which can be levied in any year, which may be expressed as a percentage of the initial transitional **congestion charge**;

    c. the process for phasing-out the transitional **congestion charge** under clause 60(b) must result in it being phased out completely within five years of the **TPM** entering into effect. However, the process under clause 60(b) may allow Transpower, during this phase-out period, to temporarily pause the phase-out or increase the transitional **congestion charge** up to a specified maximum amount, including by reinstating a transitional **congestion charge** which has already been phased out, where Transpower considers that doing so would, in its 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 clause 60(d) below to extend that period; 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 **congestion 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 clause 60 above, after the **TPM** is implemented, Transpower may propose to introduce a new transitional **congestion charge** as part of a review under clause 12.85 of the **Code**. In proposing a new transitional **congestion charge**, Transpower must provide to the Authority such information as the Authority requires to assess Transpower's proposal. Clause 60 applies, with any necessary modifications, to a new transitional **congestion charge** introduced under this clause.

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 investments** in the **interconnected grid** and related services, including transmission alternatives, that contribute to Transpower's **recoverable revenue**.

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 standard method as described in clause 21, a simple method as described in clause 22 or a combination of both but need not be the same as any other standard, simple or combined method provided for in these **Guidelines**;

   b. must provide for the **benefit-based charge** for such **benefit-based investments** to be capped at Transpower's reasonable estimate of 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: allocation of 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.

3 Stakeholder engagement and process

5. Chapter 4 (Grid Asset Classification) describes our stakeholder engagement and process for connection charges, including additional components A and B.
6. Chapter 5 (Connection Charges) describes our stakeholder engagement and process in relation to additional components C and F.
7. Chapter 15 (Transitional Congestion Charge) describes our stakeholder engagement and process for additional component D.
8. We did not seek feedback from our stakeholders on additional components E and G.

4 Summary of our decisions for each additional component

9. Under clause 54 of the Guidelines, Transpower must propose to incorporate an additional component in the TPM if, in our reasonable opinion, we consider doing so would better meet the Authority's statutory objective than not implementing it.

10. Our proposal is to adopt additional components A and B. We are not proposing to adopt any of the other additional components for the reasons set out below and in the detailed chapters. For those additional components, we have not come to the reasonable opinion that implementing each additional component would better meet the statutory objective than not implementing it.

4.1 Additional components A and B

11. We propose to incorporate additional component A ("adjustments to charges for staged commissioning"). Additional component A is intended *"to address any inefficient incentives for a customer to seek to avoid staged commissioning."*[1] Our proposal will allow connection assets to be treated as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned. Our reasons are set out in Chapter 4 (Grid Asset Classification). This proposal is reflected in clause 22(4) of the TPM.

12. We also propose to incorporate additional component B ("charges for assets principally providing connection services"), by including "*a method to ensure that **connection assets** cannot be changed into **interconnection assets** by a person other than Transpower investing in other assets that create an interconnection loop*".[2] Our reasons are set out in Chapter 4 (Grid Asset Classification). This proposal is reflected in clauses 19(1) and 21(3) of the TPM, through the definition of "grid assets".

13. We consider that adopting each of these additional components better meets the Authority's statutory objective than not adopting them.

4.2 Additional component C and F

14. We are not proposing to incorporate additional components C ("charges for connection investments to use a method substantially the same as for benefit-based charges") or additional component F ("allocation of opex") as part of connection charges. Our reasons are set out in Chapter 5 (Connection Charges).

4.3 Additional component D

15. We are not proposing to incorporate additional component D ("transitional congestion charge").[3] Following feedback received from our stakeholders and the Authority, we were not able to reasonably conclude that we could propose a TCC at this time that would be consistent with the Guidelines. We concluded that the tools available to the system operator

---

[1] Reference document #3 2020 Decision, paragraph 14.7.

[2] Reference document 4 Guidelines, clause 56

[3] We note that this does not exclude a TCC being introduced in the future, if required. Clause 61 of the Guidelines confirms that after the TPM is implemented, Transpower may still propose to introduce a new TCC as part of an operational review (under clause 12.85 of the Code).

and grid owner are sufficient controls to mitigate short term elevated congestion risk arising from removal of RCPD. Our reasons are set out in Chapter 15 (Transitional Congestion Charge).

4.4 Additional component E

16. We are not proposing to incorporate additional component E ("including additional pre-2019 investments in the benefit-based charge"). We have not come to the reasonable opinion that implementing additional component E would better meet any limbs of the Authority's statutory objective to an extent that would outweigh the costs of doing so.

17. There is a practical constraint on our ability to adopt additional component E, which is the requirement that the BBCs under additional component E must "*be capped at Transpower's reasonable estimate of 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***". The requirements for the simple and standard BBC methods in the Guidelines do not allow a cap to be applied based on aggregate positive net private benefit. Introducing a cap would require substantial new methodological development and/or potentially entirely new BBC method(s) which would substantially differ, and be more complex than, the proposed BBC methods developed under main component 2 of the Guidelines.

4.5 Additional component F

18. We are not proposing to incorporate additional component F in determining the covered costs attributable to BBIs, for the purposes of the BBC. We consider the administrative difficulties, and associated expense, of directly attributing all opex categories to BBIs, to the extent it would even be possible to do so, would not be justified by any efficiency gains, especially against the counter-factual of our proposals for opex attribution. Our reasons are set out in Chapter 6 (BBC Covered Cost).

4.6 Additional component G

19. We are not proposing to incorporate additional component G (kVAr charge) at this time. We have not come to the reasonable opinion that adopting additional component G would better meet any of the limbs of the Authority's statutory objective than not adopting it. In particular, we have not been able to reasonably conclude that including a kVAr charge would better satisfy the reliable supply or efficient operation limbs of the statutory objective. This is principally because we consider static voltage stability concerns can generally be managed by relatively low cost transmission components (capacitors and reactors). We also consider a kVAr charge would add significant complexity (and so development and implementation cost) to the new TPM that is unlikely to be offset by material efficiency or reliability benefits.

20. As an example, we note that in the Waikato and upper North Island region, due to the high level of static to dynamic reactive power sources, we will need additional dynamic plant to manage static voltage collapse during peak periods as load grows and generation exits the region. For this specific problem, a kVAr charge would not necessarily help to mitigate the issue, as the problem is caused by transmission lines absorbing reactive power, rather than the power factor performance of our customers. Following the Commerce Commission's

recent approval of the Waikato and Upper North Island Voltage Management project, we consider we have the ability to manage near-term voltage risks in this region.

21. We also note that if we consider proposing a kVAr charge in the future we will have to work through the Authority's intent that any kVAr charge would be "*based on the aggregate kvar draw of off-take transmission customers, at times of regional coincident peak demand*" and that the kVAr charge would be "*set … at the long run marginal cost of grid-connected static reactive support investment*"[4] and the issues the Authority subsequently raised in respect of both RCPD/permanent congestion of peak charging and LRMC pricing.[5]

5 Consistency with the Guidelines

22. The Guidelines require us to decide whether to incorporate the additional components into our TPM proposal. Having considered each additional component against the statutory objective, the TPM reflects our decision to incorporate additional components A and B. We consider our proposals for additional components A and B are fully compliant with clauses 55 and 56 of the Guidelines respectively. See the Guidelines compliance matrix attached to this paper.

4 Presentation by the Electricity Authority TPM Issues and Proposal, slide 14 Network reactive support services

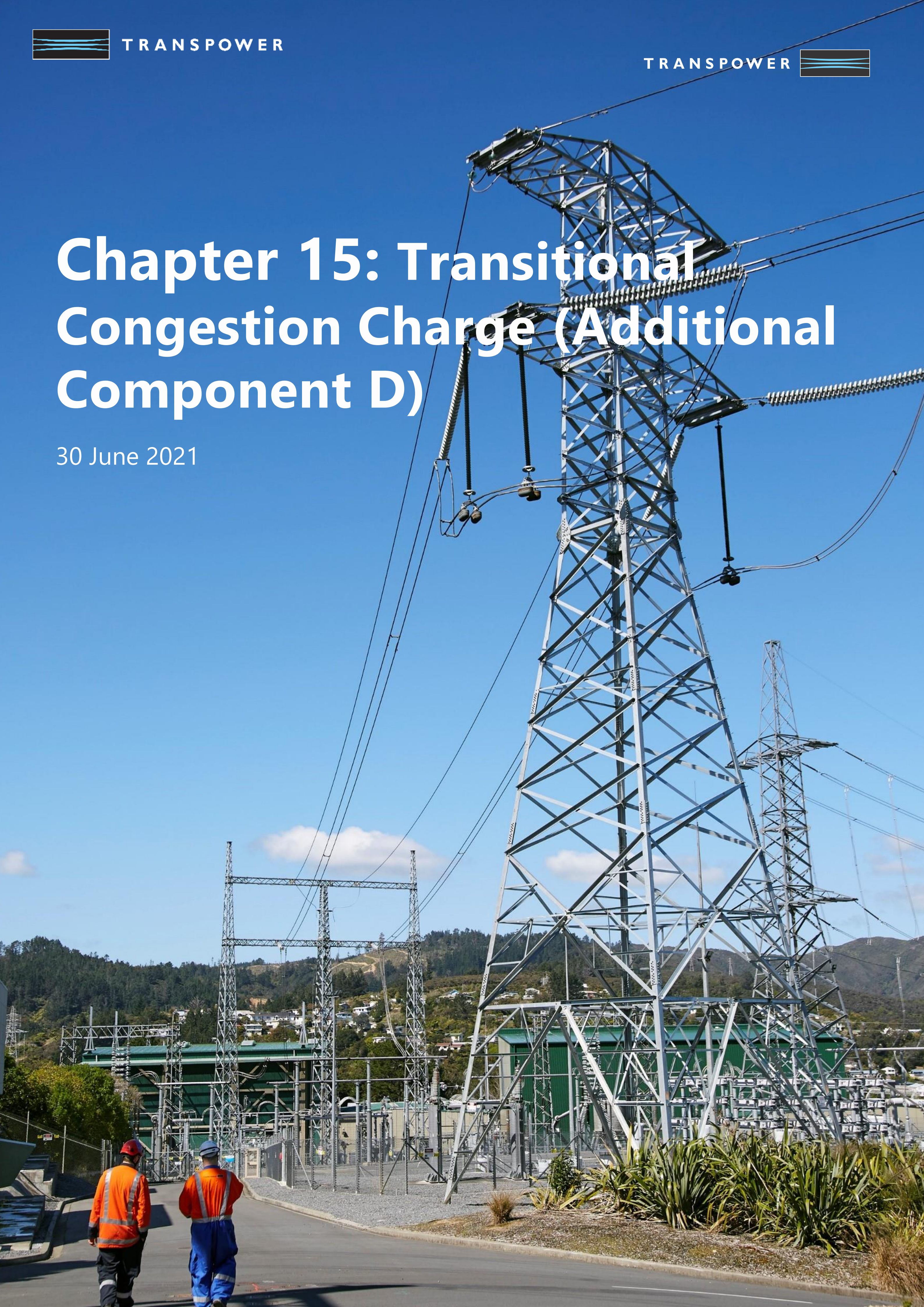
5 For example, see reference document # 1 2019 Issues paper, page iii, 244 and reference document #3 2020 Decision, page 143, 144.

TRANSPOWER

TRANSPOWER

Chapter 15: Transitional Congestion Charge (Additional Component D)

30 June 2021



Contents: Chapter 15

1 Introduction

1. This chapter explains and summarises the reasons for our decision not to include a transitional congestion charge (**TCC**) in our TPM proposal.

2. This does not exclude a TCC being introduced in the future, as clause 61 of the Guidelines provides for a TCC to be proposed either as part of this proposal, or later via an Operational Review of the new TPM after it has taken effect.[1]

2 Requirements of the Guidelines

3. Clause (viii)(a) of the Guidelines states the intent for any TCC:

> Transpower must include each **additional component** in the **TPM** if doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**.
>
> …
>
> d. Transitional **congestion charge**. The purpose of this component is to efficiently influence grid use for a limited transitional period, or if the Authority agrees, for a more extended period, when it is expected that the grid might become congested, if other means of controlling or influencing demand, including nodal pricing and

[1] Clause 61 of the Guidelines: "*Notwithstanding clause 60 above, after the TPM is implemented, Transpower may propose to introduce a new transitional congestion charge as part of a review under clause 12.85 of the Code.*"

administrative load control associated with scarcity pricing, are not adequate to meet this objective.

...

4. Clause 54 contains requirements for proposing additional components, including any TCC:

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**:

...

d. a transitional **congestion charge**, as described in clauses 58 to 61;

...

5. Clauses 58 to 61 contain the requirements for any TCC:

Additional component D: transitional congestion charge

58. This component must provide a method for determining, in respect of a transitional **congestion 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 **congestion charge** may only apply in respect of those geographic areas, circuits or other circumstances in which Transpower expects, in its reasonable opinion, there is a significant likelihood of congestion occurring without a transitional **congestion charge**.

59. If Transpower determines to include a transitional **congestion 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 efficiently controlled by the other means, including nodal pricing and administrative load control associated with scarcity pricing.

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

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

b. the **TPM** must include the process for phasing out the transitional **congestion charge**, including specifying the maximum transitional **congestion charge** which can be levied in any year, which may be expressed as a percentage of the initial transitional **congestion charge**;

c. the process for phasing-out the transitional **congestion charge** under clause 60(b) must result in it being phased out completely within five years of the **TPM** entering into effect. However, the process under clause 60(b) may allow Transpower, during this phase-out period, to temporarily pause the phase-out or increase the transitional **congestion charge** up to a specified maximum amount, including by reinstating a transitional **congestion charge** which has already been phased out, where Transpower considers that doing so would, in its 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 clause 60(d) below to extend that period; 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 **congestion charge** that may be levied in any year, the time limit on or duration of the phaseout period. Transpower must provide to the Authority such information as the Authority requires to determine an application under this paragraph.

61. Notwithstanding clause 60 above, after the **TPM** is implemented, Transpower may propose to introduce a new transitional **congestion charge** as part of a review under clause 12.85 of the **Code**. In proposing a new transitional **congestion charge**, Transpower must provide to the Authority such information as the Authority requires to assess Transpower's proposal. Clause 60 applies, with any necessary modifications, to a new transitional **congestion charge** introduced under this clause.

3 Stakeholder engagement and process

6. Transpower's initial assessment of the possibility of adding a TCC to the TPM, having regard to the time available to develop the TPM, was that the Authority's statutory objective would be best met by deferring development of any TCC and focusing on preparation of other components of the TPM.[2] However, the Authority indicated its preference for Transpower's initial analysis of a TCC to be submitted to Checkpoint 1.[3] Transpower and the Authority subsequently agreed an approach and indicative timetable to progress consideration of a potential TCC.[4]

3.1 Stakeholder workshops and feedback

7. To support our initial analysis, on 6 October 2020 we held online workshops on the TCC, chaired by an independent facilitator, with a group of sector participants who were invited to share and explore their views with Transpower in relation to any TCC in the proposed TPM. In its 2020 Decision, the Authority had indicated to stakeholders that Transpower would hold workshops.[5]

---

[2] Reference document #6 Letter to EA: Project Timeline

[3] Reference document #7 Letter from EA: Project Timeline

[4] Reference document #13 Letter to EA: Checkpoint 1 and 2 update: Transpower wrote to the Authority, on 22 September 2020, noting: *"We have agreed with the Authority's TPM team an approach to progress the Transitional Congestion Charge (TCC) in relation to the Checkpoint 1 process. This approach is outlined below:*

- *sector workshops scheduled for 6 October with a selected group of participants representative of the industry (including an Introduction from the Authority by way of a recorded video).*
- *invitation of feedback from wider industry participants based on recordings of the workshops published to Transpower's website, closing 21 October, and*
- *incorporation of the feedback into our current thinking on the TCC for the Authority's consideration by 23 November. This will either document our rationale for not progressing development of a TCC for our June proposal, or our initial analysis focussing on key design choices as per the Authority's requirements for Checkpoint 1."*

[5] Reference document #3 2020 Decision, page vi.

8. Feedback from industry participants was also invited based on recordings and transcripts of the workshops and other material published on Transpower's website. Transpower's view was that, in the time available, this format provided the best opportunity to meaningfully engage with stakeholders who wished to discuss a potential TCC, while making the material available for broader comment.

9. Transpower considered feedback received, including written submissions (each of which are published on our webpage), and incorporated this feedback into our initial analysis. All workshop materials, recording and transcripts, written feedback received from stakeholders and our summary and response document are available on our webpage.[6]

3.2 Checkpoint 1

10. On 23 November 2020, we submitted our initial analysis of whether the proposed new TPM should include a TCC, and what it might look like, to the Authority's Checkpoint 1 process.[7]

11. In its feedback, the Authority requested additional detail in relation to our assessment of whether there was a problem and, if so, whether existing tools are capable of managing it: "*That is, in the absence of an RCPD charge, will the tools Transpower has available as system operator and grid owner be adequate to efficiently manage anticipated congestion on the grid, or will a TCC be required?*"[8]

12. We provided our Checkpoint 1 resubmission to the Authority on 18 January 2021. It concluded that "*we are not able to reasonably conclude that we can propose at TCC at this time consistent with the Authority's interpretation of the Guidelines*".[9]

13. In response the Authority confirmed it "*considers that Transpower's conclusion, and its decision to not propose a TCC at this time, are consistent with the available evidence and the 2020 TPM guidelines*." The Authority also confirmed it was not expecting a preliminary proposal for a TCC to be submitted to the Checkpoint 2 process.[10]

4 Summary of our decision not to propose a TCC

14. Our TPM proposal is to not include a TCC.

15. In reaching the decision not to propose a TCC we note:

    15.1. The distinction between a permanent congestion charge, for which we have advocated, and a transitory or temporary congestion charge which can have different effect and purpose.

    15.2. The practical constraint of the requirement to develop a TPM proposal by 30 June 2021. This ruled out options which would have taken longer to develop, as reflected in the Authority's concerns about LRMC as an option.

6 TPM Development Project: Transitional Congestion Charge consultation process
7 Reference document #34 Checkpoint 1 submission: TCC
8 Reference document #36 Letter from EA: Checkpoint 1 submission TCC
9 Reference document #39 Letter to EA: Checkpoint 1 resubmission TCC
10 Reference document #43 Letter from EA: Checkpoint 1 resubmission TCC

15.3. We consider that if a TCC was adopted it should be based on pragmatic design reflecting the existing regional coincident peak demand (**RCPD**) method use to allocate the interconnection charge. We are cognisant of the transition from the current TPM with RCPD to a new TPM which relies on nodal pricing, including Real Time Pricing (**RTP**), for price signalling.

15.4. Any TCC would not be a phasing out the existing peak usage signal over a period of time. Adoption of a TCC would result in a step change from RCPD, to no peak or congestion charge price signal, and then to a new congestion charge which would then be phased out.

15.5. The Authority has provided feedback that the role for any TCC does not include helping market participants to manage the behavioural or commercial changes they will have to make with the removal of RCPD and "*it would not be a correct interpretation of the Guidelines for the avoidance of high or volatile wholesale electricity prices to provide the justification for including a TCC in the proposed TPM*".[11]

15.6. We were unable to satisfy ourselves that we could demonstrate the criteria the Authority intends for a TCC could be met. This was principally due to the criteria that the congestion charge manage short-term congestion issues, as distinct from the role of the existing RCPD signal which is to manage medium to longer-team peak demand capacity investment needs.

15.7. Near-term congestion risk is highly uncertain, including because the response of other participants to multiple impending market developments is not possible to confidently predict with any accuracy based on information available now. We have concluded that the quantitative tools available to the system operator and grid owner are sufficient controls to mitigate short-term elevated congestion risk arising from removal of RCPD.

5 Stakeholder views on a potential TCC

16. Our consideration of feedback received in the workshops and in writing is provided in our Summary & Response document, and informed our initial analysis for our Checkpoint 1 submission.[12] This section provides an overview of the key themes.

5.1 Managing the transition

17. Feedback provided at the workshops, in particular, helped provide clarity that stakeholders consider a TCC could help manage the transition:

17.1. from the status quo, where EDBs have the exposure to peak pricing for transmission and tools to manage it (including ripple control);

17.2. to a new paradigm where purchasers (retailers and direct connects) are exposed to Real Time Pricing (**RTP**), including scarcity prices, and will need tools to manage that

[11] Email from Authority, "Interpretation of guidelines on TCC", dated 23 December 2020.
[12] Reference document #32 TCC engagement: Summary and Response

exposure (requiring new contractual and physical arrangements, e.g. ICP-level ripple control).

18. Two options were articulated by stakeholders:

    18.1. design a TCC framed around the Regional Coincident Peak Demand (**RCPD**) allocation method but targeted to specific locations facing congestion risks; or

    18.2. do not include a TCC in the proposed new TPM.

5.2 Whether there should be a TCC

19. There was a near consensus view, from those who attended the online workshops and those who provided written feedback, that consideration should be given to potential transitional impacts associated with removing the RCPD interconnection charges (colloquially described as going "*cold turkey*" by IEGA).

20. For example, Network Waitaki submitted that "*a TCC is necessary to avoid unintended consequences of removing the Regional Coincident Peak Demand (RCPD) charge …*". Trustpower submitted that "*… there was strong opposition from Transpower's customers to the immediate removal of the regional coincident peak demand (RCPD) charge in the consultation on the 2020 Guidelines*".

21. We note Trustpower's submission about the risk of unintended consequences given that "*Peak demand charging has suppressed network and generation investment and offtake for decades and the sudden removal of all forms of peak demand charging creates uncertainty in terms of the magnitude of the previously unseen demand that may come forward and the embedded demand response that may drop out*". This is consistent with the Authority comment that "*We accept there is a risk that demand peaks may not be adequately controlled if the mitigants the Authority is expecting to be in place are not implemented as anticipated*".[13] A change from a long-standing coincident peak demand-based charge to a new alternative TCC option would result in uncertainty about whether peak-demand would continue to be suppressed in the same way, and the risks that could arise of congestion arising during the transition i.e. an alternative TCC could have different and uncertain impacts on demand.

22. Some evidence and analysis was provided, particularly by Trustpower and IEGA, on why incorporating a TCC in the TPM would satisfy the statutory objective, and better satisfy the objective than not including a TCC or reliance on nodal pricing etc.

23. KCE and Trustpower did not consider the Authority's statutory objective would be satisfied by a TPM proposal without a TCC.

24. Orion, on the other hand, raised questions about whether a TCC should be adopted e.g.: "*In the absence of an RCPD charge or TCC, there remain a number of compelling incentives to continue to manage load. While not all incentives will apply to all parties, the combination of incentives is likely to make a TCC redundant*".

25. Orion had previously commented, in submission to the Authority, that while it supports a permanent peak or congestion charge, it doesn't support a temporary or transitional charge: "*We believe that some form of peak pricing can play an important role in ensuring that grid*

[13] Reference document #3 2020 Decision, page vi.

investments are efficient – the right size at the right time", a "*conditional and time bound*" peak-charge "*renders the concept empty*".[14]

26. emhTrade also raised concerns about unintended consequences at the first workshop and a preference for not including a TCC on the basis it would delay parties committing to the new paradigm: "*there's actually a strong argument for not having a transition, … because you are slowing down those signals getting to those parties that are going to be exposed to them eventually, which also reduces the incentives to make those, probably technological changes that are going to enable this [transition]… Start sending those signals as soon as possible, so that the incentives are then built for that world, rather than just creating incentives to delay building for that world.*"[15]

5.3 Preferred TCC option

27. The uniform view expressed amongst stakeholders who commented, both at the workshops and in written submissions, was that if there is a TCC it should be based on a modified/targeted version of RCPD i.e. adoption of a Targeted Coincident Peak Demand (**TCPD**) charge. For example:

    27.1. Mercury "*recommend preservation of the status quo arrangements (i.e. RCPD-like) as much as possible*".

    27.2. MEUG presented (though not as a recommendation) a strawperson modified-RCPD option.

    27.3. Network Waitaki consider that the TCC "*… should … be similar to the current RCPD charge, though more granular to target specific areas of congestion on the core interconnected grid*".

    27.4. Northpower submitted "*Retaining RCPD is the most efficient option*".

    27.5. Trustpower, supported by advice from The Lantau Group, expressed a preference for "*retaining, retuning and phasing out of the RCPD charge*" including on the basis of simplicity and that "*it is the most practical, simple and most likely to secure the desired outcomes of a risk-free transition*".

6 Our initial thinking

28. We provided our initial view on the role for any TCC in the new TPM in our TCC Checkpoint 1 submission. This was based on our understanding of the Guidelines' TCC requirements:

    > 22. A TCC has a potential role in 'filling the gap' from the move from the current TPM, which has a peak or capacity charge as a core component, to a new TPM framework in which nodal pricing/RTP is relied on to manage grid-use. If the TCC is to serve this role effectively it needs to be designed to manage the behavioural and commercial changes that market participants will have to make.[16]

---

14 Orion, Submission on Transmission Pricing Review – 2019 Issues Paper, 1 October 2019, paragraph 42.
15 Reference document #18 TCC workshop #1: transcript
16 Reference document #34 Checkpoint 1 submission: TCC, paragraph 22.

6.1 Clarification of the Authority's intent for any TCC

29. However, the Authority's feedback conveyed a different and narrower intent for any TCC. Consequently, we sought clarification of the Authority's interpretation of clause 59 of the Guidelines, which, along with the statutory objective test in clause 54 and the targeting requirement in the last part of clause 58, sets the threshold for Transpower to propose any TCC.[17]

30. Authority staff advised that "*it would not be a correct interpretation of the Guidelines for the avoidance of high or volatile wholesale electricity prices to provide the justification for including a TCC in the proposed TPM*".[18] The explanation provided reflected that:[19]

    30.1. The Authority is confident the new TPM will not materially impact reliability of supply in periods of peak demand or congestion but included the TCC in the Guidelines "*in response to uncertainties (for example, around distributors' use of ripple control) particularly at the outset of a new TPM, that could result in congestion*".

    30.2. This then means Transpower needs to assess whether the other tools available to the grid owner and system operator will be "*adequate to efficiently manage anticipated congestion on the grid*", based on its analysis of the extent of congestion risk.

    30.3. "*The TCC is not intended to be a tool to control high or volatile nodal prices*" which "*can provide valuable information, signalling the time and locations where more flexible generation, demand response or a transmission response would be most valuable*" noting that "*various services are available to help market participants manage price risk*."

31. The Authority's feedback also clarified that when clauses 54, 58 and 59 are read together, the Authority considers that they only permit Transpower to propose a TCC where Transpower expects, in its reasonable opinion:

    31.1. there are geographic areas, circuits or other circumstances where there is a significant likelihood of congestion without a TCC, and

    31.2. where such congestion arises grid demand will not be efficiently controlled by other means, and

    31.3. including a TCC in those circumstances would better meet the Authority's statutory objective.

6.2 Qualitative assessment against the Authority's intent

32. Consequently, for our resubmission to the Checkpoint 1 process,[20] we completed a qualitative risk assessment but were not able to reasonably conclude we can propose a TCC, at this time, that satisfied the Authority's interpretation of the Guidelines' requirements for a

---

[17] Clause 59 requires that "*If Transpower determines to include a transitional **congestion charge** in the TPM, it must include … an explanation as to why it considers that grid demand will not be efficiently controlled by the other means, including nodal pricing and administrative load control associated with scarcity pricing.*" Clause 54 requires that Transpower must propose a TCC "*where including that component would, in Transpower's reasonable opinion, better meet the Authority's statutory objective*". Clause 58 says any TCC "*may only apply in respect of those geographic areas, circuits or other circumstances in which Transpower expects, in its reasonable opinion, there is a significant likelihood of congestion occurring without a [TCC].*"

[18] Email from Authority, "Interpretation of guidelines on TCC", dated 23 December 2020.

[19] Including by reference to the Authority's information paper, "Peak charges under proposed TPM guidelines", March 2020.

[20] Reference document #40 Checkpoint 1 resubmission: TCC

TCC. This was principally due to the criteria that the congestion charge manage short-term congestion issues, as distinct from the role of the existing RCPD which is to manage medium to longer-team peak demand capacity investment needs. The Authority's response was to accept this decision and confirm it did not expect to receive a preliminary proposal for a TCC at Checkpoint 2.

33. Near-term congestion risk is highly uncertain, including because the response of other participants to multiple impending market developments is not possible to confidently predict with any accuracy based on information available now. We have concluded the quantitative tools available to the system operator and grid owner are sufficient controls to mitigate short-term elevated congestion risk arising from removal of RCPD, allowing time for a pragmatic TCC to be developed and proposed later when it can be informed by better information about any congestion risk it may be needed to address. Clause 61 of the Guidelines provides that Transpower may propose to introduce a new TCC as part of a review under clause 12.85 of the Code.

34. The Authority has noted its support for "*Transpower's approach to remain open to the possibility that in the future, with more information on how stakeholders respond to pricing absent an RCPD component, Transpower may wish to reconsider this position, likely via an operational review of the TPM*" and confirmed "*the Authority's willingness to consider any proposed variation of the TPM containing a TCC that Transpower may wish to submit to the Authority in the future.*"[21]

7 Does Transpower's analysis indicate a TCC would meet the Guideline requirements?

35. In summary, having completed a qualitative risk assessment, we were not able to reasonably conclude that we could propose a TCC at this time consistent with the Authority's interpretation of the Guidelines for any TCC in the new TPM. Near-term congestion risk is highly uncertain, including because the response of other participants to multiple impending market developments is not possible to confidently predict with any accuracy based on information available now. We have concluded that the tools available to the system operator and grid owner are sufficient controls to mitigate short term elevated congestion risk arising from removal of RCPD, allowing time for a pragmatic TCC to be developed and proposed later (if required) when it can be informed by better information about the congestion risk it is needed to address.

36. The information and assessment on which we have relied to reach this conclusion is discussed below.

7.1 Congestion risk assessment and uncertainties

37. Congestion on the grid typically arises when demand peaks. Whether peak demand will actually give rise to congestion depends on the operational state of the grid and system at

[21] Reference document #43 Letter from EA: Checkpoint 1 resubmission TCC

the time, including whether system capacity is limited/constrained due to grid or generation outages or due to operational decisions of market participants (for example, the prices at which generation is offered and whether distributors and/or consumers take steps to manage demand for their own purposes).

38. Typically, the system operator manages forecast congestion on the grid through scheduling higher-priced (out-of-merit) generation and/or dispatchable demand. The result will be elevated prices in the transmission-constrained region that may then incentivise voluntary demand reduction and/or generation increase by participants not subject to dispatch.

39. However, if there is insufficient market and voluntary response to manage the congestion, the system operator can instruct involuntary load-shedding (administrative load control).

40. Involuntary load-shedding may, if it occurs frequently 'enough', be an inefficient outcome. Perhaps more importantly, it is unlikely that frequently shedding load involuntarily, particularly load that has noticeable downstream effects on consumers, will meet the expectations of our customers and consumers.

41. How congestion risk will evolve in the early years of the new TPM is materially uncertain, including because at this time we are not able to predict, with any confidence or accuracy, the expected behaviour of other participants in response to:

    41.1. The end of the RCPD price signal after 31 August 2021 (given the Authority's signal that the last year for prices set under the current TPM will be from April 2022),

    41.2. The introduction of RTP, which is planned for October/November 2022,

    41.3. The price signals provided by the benefit-based charge (**BBC**) under the new TPM, which are already in effect but with uncertainty until the form of the BBC and its price outcomes become more clear,

    41.4. Distribution pricing reform, which is expected to accelerate and evolve differently per distributor, and

    41.5. The expectation that electrification will accelerate as a key limb of New Zealand's climate change response, including through the adoption of new technologies at grid and distribution level, and within ICPs.

42. The assessment that we have undertaken considers parts of the grid where our current forecasts and system planning anticipate congestion issues could arise and includes a qualitative assessment of the impact on congestion in the absence of the price signal provided by RCPD, recognising uncertainty prevails.

7.2 How congestion risk change without RCPD is unclear at this time

43. We consider the removal of RCPD will result in an increase in peak demand (to at least some extent) and consequently risk that congestion will occur more often. However, we are not able to assess quantitatively how often congestion might occur or how much load might be shed involuntarily with or without a TCC in the new TPM ahead of understanding how

participants will respond to other industry developments, including the transition to RTP nodal prices.[22]

44. Consistent with our January 2021 Checkpoint 1 resubmission to the Authority, we are continuing separate work on assessing the potential impacts of RCPD removal on peak loads. Since January Transpower, as the grid owner, engaged (as is usual each year) with load customers about their demand forecasts. This year they were asked whether the move away from RCPD-based charging would change their level of load control or demand response. Responses received indicate our load customers are generally still uncertain about how their behaviour will change. Also in February Transpower, as the system operator, invited comment on its approach and sensitivities to its 2021 Security of Supply Annual Assessment. The paper presented the changes to transmission pricing as a sensitivity to its three scenarios. No comments were received (although more immediate supply security matters may have been forefront). The annual Security of Supply Forecast is due for release later this year.

45. We consider a load currently controlled by distributors in response to RCPD signals (such as hot water load) will generally continue, near-term, to be controlled should the system operator need it at times of congestion, including in the absence of a TCC. Some other load, such as industrial load, will be able to respond to nodal price signals should they wish.

7.3 How likely is near-term congestion risk, and where?

46. An increase in peak demand due to a removal of RCPD is less likely to elevate congestion risk in the centre of the grid backbone where congestion can typically be managed by dispatching generation through the wholesale market. However, an unexpected increase in peak demand would be of more concern where there is a lack of capacity at the extremities of the grid especially where more local generation is unavailable or insufficient to mitigate congestion. The main adverse impact, if the TPM doesn't signal the cost of peak-usage, is that it will bring forward transmission investment, but this is a dynamic efficiency consideration and outside the short-term function of any TCC.

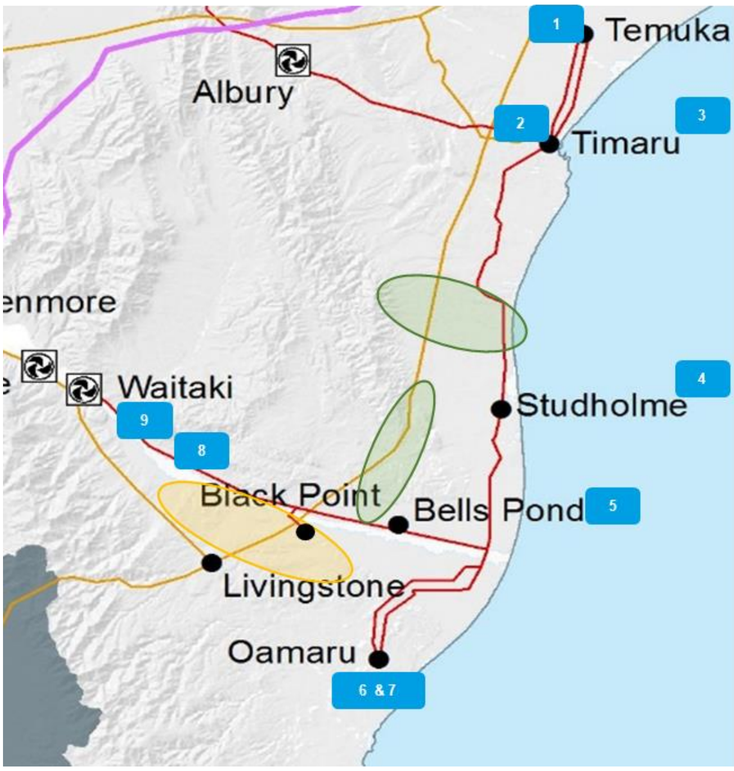
47. There are two regions at the extremity of the grid where, based on current demand and generation forecasts, we are already investing, or expecting to invest relatively soon, in order to reliably supply peak demand (reliably avoid inefficient congestion). We expect these regions to present the greatest risk of elevated congestion risk in the early years of the new TPM. In both cases grid solutions to resolve the risk are well progressed to resolve the needs ahead of their forecast need date:

    47.1. Waikato and the Upper North Island (**WUNI**), including as a consequence of anticipated retirement of the Huntly Rankine units, and also because peak demand is forecast to grow: a major grid investment to address this need has been approved by the Commerce Commission and the first component of the WUNI Voltage Management (**WUNIVM**) project is in progress and planned to be commissioned prior to winter 2023. Additional phases of the project are unlikely to be required before winter 2025.[23]

[22] Where and how much load might be shed in response to any TCC will also be a function of the design and parameters of that TCC.
[23] Based on our current understanding of the timing of thermal generating plant closures.

47.2. The Upper South Island (**USI**) where peak demand (both summer and winter) is forecast to continue growing and already requires active load control by local distributors at times of peak demand. In 2013, the Commerce Commission approved the enabling works for our preferred option to increase capacity into the Upper South Island, including procuring the necessary designations, easements, and property. The build phase of the project is currently forecast to be required as early as 2027.

48. It is possible that other, more localised points of congestion may arise[24], including on connection assets. We will continue to manage these with the relevant customers as they arise and evolve. These localised points of congestion can usually be managed for several years without requiring pre-contingency load restrictions. For example, and as shown by the picture below, over the last 10 years we have worked with distributors in South Canterbury to increase grid capacity using incremental, lower cost measures including special protection schemes (**SPS**s), ripple control, grid reconfigurations and demand response.



CASE STUDY: SOUTH CANTERBURY PARTNERSHIP WITH DISTRIBUTORS

1. Temuka Supply Transformer SPS
2. Timaru Demand Response
3. Timaru Interconnecting transformer and Supply Transformer SPS
4. Studholme Split Closed and Auto Changeover Scheme installed
5. Bells Pond Demand Response
6. Oamaru Demand Response
7. Oamaru wider voltage limits
8. NWL and AEL Waitaki Valley irrigation ripple control
9. Waitaki, Black Point, Bells Pond, SPS

49. Based on this qualitative assessment we consider, while the absence of RCPD is likely to increase congestion risk, it is unlikely to do so widely across the grid, and our system plan, work programme, and mitigations (including those identified in the next sub-section) are sufficient to limit the consequences for our customer and consumers efficiently.

---

[24] For example, on the Bombay-Otahuhu 110 kV circuits, for which we have a proposal to mitigate this issue currently being evaluated by the Commerce Commission.

7.4 Controls for mitigating congestion risk

50. Both the grid owner and system operator have a suite of tools to mitigate congestion risk, including those we introduce in this section.

Grid owner controls

51. Outside the TPM and grid investment that is already in progress, tools available to the grid owner to mitigate unexpected congestion risk include:

    51.1. Grid Support Contracts: these are considered as a means of avoiding or delaying grid investment, including as part of the major capital and listed project investigation process;

    51.2. Demand response, including where contracted by distributors to help manage their investment in connection assets, their own investments and (we expect) avoid or delay future benefit-based investments in the interconnected grid and associated BBCs.

    51.3. In some cases, we may be able to manage unexpected congestion in the short-term using tools such as special protection schemes, which are generally quicker and cheaper to install than primary plant solutions.

    51.4. Load agreements and outage scheduling: load agreements are formed between the grid owner and distributors or direct connects to limit their load during planned outages, on advice from the system operator that system security would otherwise be at risk. Load agreements are taken as a last resort, the grid owner's preference being to schedule outages at times when load management is not required.

System operator controls

52. The system operator is responsible for managing the real-time power system and operating the wholesale electricity market. The system operator continually updates the load forecast and together with updated bids and offers from market participants and updated system constraints (including transmission constraints), calculates and publishes forecast market prices and other information to market participants.

53. The system operator will typically manage forecast congestion issues using system constraints to dispatch more generation and/or less dispatchable demand in the transmission-constrained region avoiding the need for controlling load. Sometimes the systems operator applies system splits which avoid the need for controlling load but may expose a small amount of load to risk of loss of supply in the event of a circuit trip.

54. However, sometimes there remains insufficient generation and transmission capacity to supply the forecast load in a region and an infeasibility is forecast.[25] The system operator takes the following steps in response to "*forecast infeasibilities*" (deficits) to avoid real-time load-shedding wherever possible:[26]

    54.1. Permit reserves deficits, but not for system risks that AUFLS is scheduled to cover.[27]

---

25 Currently very high constraint violation penalties (CVPs) are used to clear all market resources before encountering energy or reserve infeasibilities. Under RTP, reserve and forecast demand will include default scarcity prices rather than the current CVPs. These scarcity prices under RTP could be used for settlement if the scarcity of energy and/or reserve is the marginal resource.

26 It is anticipated that similar steps would be used under RTP.

27 Extended Contingent Events (ECE). ECE are larger, less likely risks such as the tripping of both poles of the HVDC simultaneously.

54.2. 36 hours ahead: publish forecast schedules and automated warning notices to make participants aware energy and reserves needs cannot be met for the offered resources (energy, reserve and transmission capacity). Notices also warn participants of any energy or capacity issues should the largest single source of generation trip off.

54.3. Before Gate Closure[28]: Further warning notices are issued to highlight concerns with power system's ability to maintain secure operations. These are an escalation of the automated warning notices and are issued in sufficient time for market participants to freely alter their generation and reserve offers. They request participants undertake actions which would alleviate the forecast shortfall, including increasing generation and reserve offers and decreasing load.

54.4. After Gate Closure: If forecast deficits continue into the gate-closure period, a Grid Emergency would be declared via a Grid Emergency Notice (GEN). A GEN would request increased offers of generation and reverses be made available and request demand reduction. The GEN allows re-offering within the gate closure period and details the emergency steps the system operator may take to manage the power system.

54.5. Real-time: If a deficit exists in real-time the system operator can require load control to alleviate the deficit situation[29]. The quantity of the imbalance is allocated to the distribution companies in the affected area pro-rata and communicated via a Demand Allocation Notice (DAN). In practice the load control instructions manifest as a maximum limit rather than a 'delta'. Load control instructions are rescinded in a controlled manner once system conditions allow.

54.6. Through the multiple signalling channels, prices and notices, we would also expect voluntary load shedding from distribution companies and price sensitive industrial load to have occurred.

7.5 Effectiveness of controls for mitigating elevated congestion risk

55. As discussed above, we have considered the prevailing uncertainty about how other participants will respond to other market developments, and qualitatively assessed that the absence of RCPD is likely to increase congestion risk, but is unlikely to result in widespread congestion across the grid.

56. Our assessment concludes that, should the incidence of congestion materially increase the frequency or extent to which the system operator must shed load – potentially in places we have not anticipated above – the controls available to the system operator will limit load shedding and ensure the grid is secure, and the grid owner controls can respond quickly enough to limit the impact on consumers efficiently.

57. We also think it likely that any practical TCC we might propose would result in load sometimes being shed by participants in anticipation of congestion that would not, in the end, have occurred by relying on the market process to minimise the need for involuntary load shedding.

[28] This is currently 1 hour.

[29] See Clause 6(2) in Schedule 8.3, Technical Code B of the Code.

58. We consider the grid owner and system operator and tools summarised above are sufficient to mitigate and manage near-term congestion risk arising from the removal of RCPD. In our view, relying on these tools can provide short-term mitigation of any unanticipated and relatively frequent congestion. We think this approach can, if it proves necessary, provide time to develop and propose a pragmatic TCC later when it can be informed by better information about the congestion risk it may be needed to address.

7.6 Statutory objective assessment

59. Clause 54 of the Guidelines requires Transpower to include a TCC in the TPM if including it "*would, in Transpower's reasonable opinion, better meet the statutory objective than not including that additional component*." Also, clause 59 requires Transpower to, if Transpower decides to include a TCC in the TPM, provide "*an explanation as to why it considers that grid demand will not be efficiently controlled by other means, including nodal pricing and administrative load control associated with scarcity pricing.*" It is a consequence of clause 59 that a TCC should not be included in the TPM if Transpower considers grid demand can be efficiently controlled by means other than a TCC.

60. We are cognisant that the Guidelines are not asking us whether a TCC would be to the long-term benefit of consumers, but whether a TCC applied for the sole purpose of managing short-term congestion/capacity issues would be to the long-term benefit of consumers. Having further considered the Authority's limited intent for any TCC, we have concluded it is not possible to reasonably make the case that including a TCC would better meet the Authority's statutory objective than not including one. In terms of the statutory objective, its underlying purpose "*for the long-term benefit of consumers*" and this intent, we note the following:

    60.1. Reliability: as we have discussed above the system operator is tasked with ensuring system security and has tools available to limit involuntary load-shedding to only those times when it is necessary. The grid owner has plans in place and is progressing the resolution of known material congestion risks in two regions (WUNI and USI). The grid owner also has tools that are available in the absence of a TCC to respond relatively quickly to the occurrence of unanticipated congestion.

    60.2. Efficiency: the assessment presented above has led us to conclude that we are not able to determine that any TCC proposal at this time can meet the required threshold for it to be included in the new TPM – which includes a requirement that grid demand will not be *efficiently controlled* by other means, including nodal pricing and administrative load control.

7.7 We cannot make the case for a TCC at this time

61. A key take-out from our stakeholder engagement was that TCC may help participants to manage the behavioural and commercial transition from the current TPM to a TPM that does not have a permanent peak-usage charge. However, having considered the Authority's feedback and clarification of its intent for any TCC, we have not been able to reasonably conclude that we can propose a TCC at this time on the basis of the Guidelines' requirements that:

61.1. there are geographic areas, circuits or other circumstances where there is a significant likelihood of congestion occurring without a TCC, and

61.2. we could not efficiently control grid demand using other means, and

61.3. consequently, that including a TCC would better meet the Authority's statutory objective.

7.8 Proposing a TCC at a later date

62. The Authority also noted, in its feedback on our Checkpoint 1 resubmission, that we can propose to introduce a TCC into the TPM later, and suggested it could be useful for stakeholders to understand our indicative thinking on what might trigger such a proposal and how a TCC might be designed:

63. Following the completion of the Checkpoint 1 process with the Authority, we published our TCC Checkpoint 1 submission, resubmission and the associated correspondence with the Authority. We considered that doing so would, as well as providing process transparency, help stakeholders to understand our indicative thinking regarding the indicators that might result in us developing and proposing a TCC in future, and how we might approach its design.

8 Consistency with the Guidelines

64. The Authority's response to our Checkpoint 1 resubmission confirmed it "*considers that Transpower's conclusion, and its decision not to propose a TCC at this time, are consistent with the available evidence and the 2020 TPM guidelines.*"[30]

[30] Reference document #43 Letter from EA: Checkpoint 1 resubmission TCC

TRANSPOWER

Chapter 16: Suggested Code workability amendments

30 June 2021

Contents: Chapter 16

1 Introduction

1. In its 2019 Issues Paper, the Authority discussed making Code changes on TPM related matters, including an amendment to ensure workability of the TPM.[1] The Authority has noted it may consider consulting on the additional Code changes alongside the proposed TPM to be developed by Transpower.[2]
2. Against this background, included in this chapter are some suggested workability Code amendments the Authority may wish to consider. These amendments reflect changes that would facilitate and support implementation of the proposed TPM. While our proposed TPM is able to be implemented without the proposed Code amendments and they are not necessary to ensure consistency with the Guidelines, these matters would assist with the future implementation and workability of the proposed TPM.
3. This chapter does not include suggested drafting for the proposed Code amendments, noting that detailed clause drafting can be the subject of a separate process.

2 Frequency of operational reviews

4. Clause 12.85 of the Code states:

   12.85 **Review by Transpower**

   At any time, **Transpower** may submit to the **Authority** a proposed variation of its **transmission pricing methodology**, provided that the submission is made at least 12 months after the last **Authority** approval of the **transmission pricing methodology**.
5. Submissions to vary the TPM under clause 12.85 of the Code are generally made following 'operational reviews' of the TPM. Under clause 12.85 of the Code, Transpower may propose a variation of the TPM arising from an operational review provided the submission is made at least 12 months after the last Authority approval of the TPM.
6. The proposed new TPM represents a fundamental change of approach to calculating transmission charges (with the exception of the calculation of connection charges). It is

[1] Reference document #1 2019 Issues Paper
[2] Reference document #1 2019 Issues Paper Appendix F

probable that, as Transpower implements the proposed new TPM and calculates transmission charges for designated transmission customers, minor changes, additions or deletions may be helpful in order to enhance the TPM so that it is able to be implemented in a workable manner and as it is intended to apply. Such minor changes may only become apparent as Transpower works through the detailed implementation of the proposed new TPM. For example, it may be beneficial to consider allowing certain assumptions from Transpower's assumptions book and practice manuals to be elevated into the TPM over time. Retaining clause 12.85 of the Code in its current form may inhibit timely resolution for such facilitative changes.

7. In our view the Authority should consider amending clause 12.85 of the Code to allow Transpower to submit a proposed variation to the TPM more frequently than 12 months after the Authority last approved the TPM, if approved by the Authority.

8. The Authority previously consulted on amendments to the Code to address workability issues in the 2019 Issues Paper.[3] In our submission on the 2019 Issues Paper we proposed an amendment similar to the amendment proposed here.[4]

3 Retention of Code clauses 13.136 and 13.137

9. Clauses 13.136, 13.137 and 13.137A of the Code currently state:[5]

13.136 **Offered embedded generators to provide half-hour metering information**

(1) Using an **approved system** or by written notice, each **generator** must give the relevant **grid owner half-hour metering information** under clause 13.138 in relation to **generating plant**—

(a) that injects **electricity** directly into a **local network** or an **embedded network**; or

(b) if the **meter** configuration is such that the **electricity** flows into a **local network** without first passing through a **grid injection point** or **grid exit point metering installation**.

1A) For the purposes of subclause (1), the relevant **grid owner** is—

(a) in relation to a **generator** (other than an **embedded generator**), the **grid owner** of the **grid** to which the **generator's generation** is connected; and

(b) in relation to a **generator** that is an **embedded generator**, the **grid owner** of the **grid** to which the **local network** to which the **embedded generator** is directly or indirectly connected, is connected.

(2) To avoid doubt, subclause (1) does not apply in respect of—

(a) any **unoffered generation**; or

(b) **electricity** supplied from—

(i) *[Revoked]*; or

(ii) a **type B industrial co-generating station**.

13.137 **Unoffered grid-connected generators and grid-connected type B industrial co-generation to provide half-hour metering information**

3 Reference document #1 2019 Issues Paper

4 Transpower submission: 2019 Issues Paper

5 13.136 and 13.137 were amended in September 2019 after the Authority's decision in June 2019 to make Code amendments to delete clauses 13.136 and 13.137

(1) Using an **approved system** or by written notice, each **generator** must give the relevant **grid owner half-hour metering information** for—

(a) **unoffered generation** from a **generating station** with a **point of connection** to the **grid**; and

(b) *[Revoked]*; and

(c) **electricity** supplied from a **type B industrial co-generating station** with a **point of connection** to the **grid**.

(2) To avoid doubt, each **generator** must give the relevant **grid owner** the **half-hour metering information** required under this clause in accordance with the requirements of Part 15 for the collection of the **generator's volume information**.

(3) If the **half-hour metering information** is not available, the **generator** must give the relevant **grid owner** a reasonable estimate of such data using an **approved system** or by written notice.

10. The Authority's March 2019 consultation paper on its real-time pricing (**RTP**) project[6] included an Appendix showing proposed Code clause deletions and insertions, including the deletion of clauses 13.136 and 13.137.[7] At the time we submitted in response to the consultation that removing data and information obligations in the Code may have adverse implications outside pricing processes.[8]

11. The Authority's decision to implement RTP:

11.1 included a Code amendment deleting clauses 13.136 and 13.137;[9] and

11.2 indicated the Authority would not make these, and other associated, Code amendments (through the Gazette) until late 2021.[10]

12. We consider the Authority should consider not deleting clauses 13.136 and 13.137 of the Code as previously proposed by the Authority. Transpower requires the information generators are required to disclose under clauses 13.136 and 13.137 in order to be able to accurately calculate residual charges, which are calculated based on gross load.

4 Information about embedded activity

13. For the purpose of calculating the residual, and in order to be able to understand whether or not circumstances have occurred that require an adjustment to BBCs, under the proposed TPM Transpower will require information from designated transmission customers about activity embedded behind the customer's point of connection that is not covered by clauses 13.136 and 13.137.

14. In our view the Authority should also consider amending the Code to require designated transmission customers to monitor, record and provide to Transpower information about activity embedded behind the customer's point of connection that is relevant to administering the new TPM. Requiring designated transmission customers

[6] Remaining elements of real-time pricing 19 March 2019

[7] Remaining elements of real-time pricing 19 March 2019 – Appendix B

[8] Transpower submission on the Authority's proposal for design of the remaining elements of real-time pricing 30 April 2019

[9] Implementing spot market settlement on real-time pricing – Decision 28 June 2019 – Appendix A Code amendment

[10] Implementing spot market settlement on real-time pricing – Decision 28 June 2019

to monitor, record and provide this information to Transpower would facilitate calculation of the residual charge based on accurate gross load information.

5 Loss and constraint excess

15. The Authority previously consulted on amendments to the Code to specify a method for allocating Loss and constraint excess (**LCE**) in the 2019 Issues Paper.[11] Our view remains the same as we expressed in our submission on the 2019 Issues Paper:[12]

> … given that the FTR grid is an increasingly close approximation of the whole grid, we do not think the administrative cost of having Transpower allocate residual LCE (the part of total LCE not required for the settlement of FTRs) is justified. The task of allocating residual LCE should go to the clearing manager, who could allocate it to wholesale market purchasers in proportion to their payments as part of the normal monthly clearing process.

16. We understand the clearing manager provides a service to some of our distribution customers, which allocates the portion of LCE they receive from Transpower, as a pass-through from the clearing manager, to purchasers on their network. In our view, extending this approach to all LCE would be efficient and to the long-term benefit of consumers.

[11] Reference document #1 2019 Issues Paper
[12] Transpower submission: 2019 Issues Paper

TRANSPOWER

Appendix A: List of Clause 2 Departures

30 June 2021

RELEVANT GUIDELINES CLAUSE	PROPOSED DEPARTURE	GUIDELINES/ AUTHORITY INTENT	STATUTORY OBJECTIVE
		Connection charges	
Clause 11 of the Guidelines	**First Mover Disadvantage (FMD) Type 2** Transpower's proposal is to allow the costs of FMD Type 2 connection investments ("over-provisioning") to be spread across all customers paying the connection charge through the "asset component" of the connection charge calculation, set out in clause 27 of the proposed TPM. Transpower will reduce replacement costs to exclude any over-provisioning. The portion attributable to over-provisioning, this will be allocated to other connection assets and recovered from other customers paying connection charges. ***See Chapter 5: Part C – Connection Charges, section 10, for further detail.***	The proposal is not inconsistent with the intent of the Guidelines. Although the Guidelines do not contain express provisions dealing with FMD, paragraphs 8.6 and 8.7 of the Authority's 2020 decision demonstrate that the Authority did not intend to prevent FMD issues being addressed as part of the new TPM. The proposal upholds clause 1(c) of the Guidelines by reducing incentives for existing and potential customers to avoid transmission charges in a way that may cause economic inefficiency. It also upholds clause 1(f), in that it facilitates regulatory recovery of Transpower investments.	The proposal promotes all three limbs of the Authority's statutory objective: • It addresses the risk that first or early moving customers may be incentivised not to connect to new connection investments that have been built with additional capacity to accommodate future development. Type 2 FMD otherwise has the potential to deter future generation development, which as a result would adversely affect competition in wholesale electricity markets. Similarly, reliability would be adversely affected because there would be less generation capacity to cover planned and unplanned events. • FMD Type 2 may otherwise incentivise inefficient locational connection decisions for new generation and load. Customers may choose grid or embedded points of connection that reduce private costs, by avoiding the cost of additional connection capacity. Transpower does not expect that addressing Type 2 FMD for connection investments will result in any reduced scrutiny of connection investments and, in any event, considers that the efficiencies associated with provisioning for the future will outweigh any inefficiencies arising from reduced scrutiny. ***See Chapter 5: Part C – Connection Charges, section 12, for further detail.***
		Benefit-based charges	
Clause 17 of the Guidelines	**Covered cost: Depreciation and capital charge** The Guidelines contemplate that the TPM will use forecast depreciation and forecast return on capital for the relevant pricing year in calculating capital components. The TPM proposes to instead use the depreciation and opening RAB values for the preceding financial year. This approach achieves consistency with Transpower's IPP. ***See Chapter 6: Part D – BBC covered cost, section 4, for further detail.***	The proposal is not inconsistent with the intent of the Guidelines. While there will be a slight "mismatch" between the period used to calculate the capex components of covered cost and the pricing year for which covered cost is being calculated, over the life of the BBI its full capital cost will still be recovered through the BBC, consistent with clause 15 of the Guidelines. The departure is consistent with the principle in clause 1(b) of the Guidelines in that it facilitates greater simplicity and reduces administrative cost.	The proposal promotes the efficiency limb of the statutory objective. The use of forecast capex inputs would involve potential errors, necessitating a wash-up mechanism to ensure capex components are not over or under-recovered. Administrative burden and cost can be avoided by using actual capex inputs, instead of forecasts. ***See Chapter 6: Part D – BBC covered cost, section 8, for further detail.***
Clause 21 of the Guidelines	**Remaining life**	The proposal is not inconsistent with the intent of the Guidelines. Under clause 8 of the Guidelines, the price-quantity method (and the resiliency method and simple method) must result in an allocation that is broadly in	The proposal promotes the efficiency limb of the Authority's statutory objective. Estimating net private benefits over many decades, potentially 55 years, would increase the cost of

RELEVANT GUIDELINES CLAUSE	PROPOSED DEPARTURE	GUIDELINES/ AUTHORITY INTENT	STATUTORY OBJECTIVE
	Transmission assets have long lives. For example, the standard physical life of transmission lines and substation used to calculate depreciation is 55 years. However, for the purposes of assessing benefits under the TPM, we propose for benefits to be assessed over the remaining "useful life" of a BBI, or a 20 year period from the date of full commissioning, whichever is the shorter (see also definition of "standard method calculation period" in proposed TPM). ***See Chapter 7: Part D – BBC allocation methodology, section 13.1, for further detail.***	proportion to expected positive net private benefits. A 20-year analysis period achieves this because, beyond 20 years, costs and benefits are uncertain, particularly private costs and benefits. Assessing and quantifying those distant costs and benefits is unlikely to make the final allocation more reflective of net private benefits. In any event, the present values of distant costs and benefits would be low and would have relatively little impact quantitatively on the final allocation. A 20-year analysis period is also consistent with the investment test under the Capex IM, and therefore assists with complying with clause 23 of the Guidelines. The departure is also consistent with the principle in clause 1(b) of the Guidelines.	administering and complying with the new TPM and not produce a significantly better outcome, or any better outcome. ***See Chapter 7: Part D – BBC allocation methodology, section 13.1 and 19, for further detail.***
	Residual charge		
Clause 27 of the Guidelines – definition of "***load customer***"	**Grid-connected generators with embedded load** Clause 27 of the Guidelines requires the residual charge to apply to all designated transmission customers *to the extent they are "load customers"*. However, the definition of "load customer" in the Guidelines does not capture generators who have embedded load. Similarly, neither the HAMD formula in clause 28(a) nor the definition of "gross" in the Guidelines provides for embedded load being supplied by the generator. Under the proposed TPM, "load customers" include grid-connected generators that inject into consuming plant or a non-grid network, and that embedded load is counted for the purposes of the residual charge (see sub-definition of "supplying load customer"). ***See Chapter 8: Part E – Residual charge, section 5, for further detail.***	The proposal is not inconsistent with the intent of the Guidelines. As noted, the Guidelines do not expressly address the scenario where a generator has embedded load. The Authority's 2020 Decision and earlier papers, such as the 2019 Issues Paper, are also silent on this specific issue. However, the Authority's Checkpoint 2A feedback confirmed that the Authority does intend the residual charge to apply to generators in respect of their embedded load, consistent with a broader policy intent to avoid incentives for parties to structure their arrangements in ways that avoid transmission charges (as reflected in clause 1(c) of the Guidelines). This proposal upholds the principle in clause 1(b) of the Guidelines (practical considerations, particularly robustness and certainty). This is because for some consuming plant/generating plant configurations it may be difficult to determine whether the consuming plant or generating plant is connected directly to the grid. This proposal makes that distinction academic (see clause 5(2) of the TPM).	The proposal promotes the efficiency and competition limbs of the statutory objective. Without it, a party that would otherwise be a load customer could be incentivised to connect its consuming plant or network behind a grid-connected generator in order to avoid a residual charge, even if it would be more efficient overall for the party's consuming plant or network to be grid-connected. Furthermore, without this proposal, competitive neutrality between grid-connected and embedded consumers and network owners could be compromised because the grid connected parties would pay residual charges while embedded parties would not. ***See Chapter 8: Part E – Residual charge, section 7, for further detail.***
	Adjustments		
Clause 33(d) of the Guidelines	**Attribution of BBCs for recent BBIs to related entities** Our proposal is to extend the treatment required under clause 33(d) of the Guidelines to a related party of the exiting customer (clause 82(7) of the TPM). This is intended to prevent corporate structuring being used to avoid the 10-year rule in clause 33(d).	In its Checkpoint 2B feedback, the Authority observed that some provision will likely be necessary to deal with corporate structures that have the effect of undermining the intent of the Guidelines. The Authority has previously described the intent behind the 10-year rule in the Guidelines as being to ensure customers properly scrutinise grid investment proposals during the investment approval process and avoid	Removing a way in which the operation of the 10-year rule could be avoided better meets the efficiency limb of the Authority's statutory objective than leaving that opportunity open. ***See Chapter 8: Part E – Residual charge, section 8.1, for further detail.***

RELEVANT GUIDELINES CLAUSE	PROPOSED DEPARTURE	GUIDELINES/ AUTHORITY INTENT	STATUTORY OBJECTIVE
	This proposal departs from clause 33(d) of the Guidelines by applying the 10-year rule in situations where a "related entity" of the exiting or disconnecting customer remains a customer. ***See Chapter 10: Part F – Adjustments, section 5.2, for further detail.***	creating inefficient incentives to shut down a plant to avoid the BBC. The proposal is consistent with the Authority's intent for the 10-year rule, in that it removes a potential source of avoidance behaviour by customers (e.g. transferring assets to a sister company shortly before exiting or disconnecting). This is consistent with clause 1(c) of the Guidelines (avoiding incentives to inefficiently avoid transmission charges).	
Clause 33(d) of the Guidelines	**De-rating of existing plant** Our proposal is to treat a large de-rating of plant as if it were disconnection of large plant of the same size and adjust BBCs accordingly (clause 78(3) of the TPM). This is an additional adjustment event not required by the Guidelines. ***See Chapter 10: Part F – Adjustments, section 5.3, for further detail.***	A large de-rating of plant has the same impact on grid use, and benefits, as a plant disconnection of the same size, and in some cases it may be difficult to discern between the two. It is therefore, consistent with the intent of clause 33(d) of the Guidelines to treat these events the same way. It is also consistent with the Guidelines' treatment of upgrades as equivalent to the connection of new plant. The proposal upholds clause 1(c) (avoiding incentives to inefficiently avoid transmission charges) and clause 1(e) (avoiding discrimination between customers) of the Guidelines.	Without the proposed departure, having different treatment based on the arbitrary factor of whether a plant is disconnected or de-rated has the potential to: • incentivise inefficient operational decisions aimed only at avoiding BBCs, e.g. choosing to close plant entirely even though there is a business case for staying open at a lower capacity; and • adversely affect competitive neutrality between customers. Accordingly, the proposal better meets the efficiency and competition limbs of the statutory objective than if the proposal were not implemented. ***See Chapter 10: Part F – Adjustments, section 8.2, for further detail.***
Clause 33(a)(ii) of the Guidelines	**Treatment of distributor changes** Our proposal is to depart from the requirements of clause 33(a)(ii) of the Guidelines by treating local network transformer upgrades and new GXPs as potential substantial and sustained increases in load and therefore adjustment events (clauses 78(1)(h), (i), 84 and 85 of the TPM). This is a departure because, in the Guidelines, "large offtake plant" does not include local networks. ***See Chapter 10: Part F – Adjustments, section 5.3, for further detail.***	The purpose of BBCs is to recover the costs of BBIs according to customers' positive NPB. For distributors, this includes *"the positive net private benefit of <u>any parties</u> whose equipment is electrically connected to the interconnected grid through the [distributor's] network"* (clause (iv) of the Guidelines, emphasis added). An increase in local network load due to accumulated residential and commercial load growth has the same impact on the distributor's grid use, and benefits, as the same growth coming from new large embedded plant, upgrades to such plant, or increases in electricity use by such plant. It is therefore consistent with the intent of clause 33(a)(ii) of the Guidelines to treat these events in the same way. The proposal is also consistent with clause 1(e) of the Guidelines (avoiding discrimination between customers).	If grid-connected distributors are not exposed to increases in BBC allocations for general load growth, this could decrease their scrutiny of grid investment decisions and may encourage small scale development in local networks when larger-scale development would be more efficient. Therefore, this proposal would better meet the efficiency limb of the statutory objective. ***See Chapter 10: Part F – Adjustments, section 8.3, for further detail.***
		Reassignment	

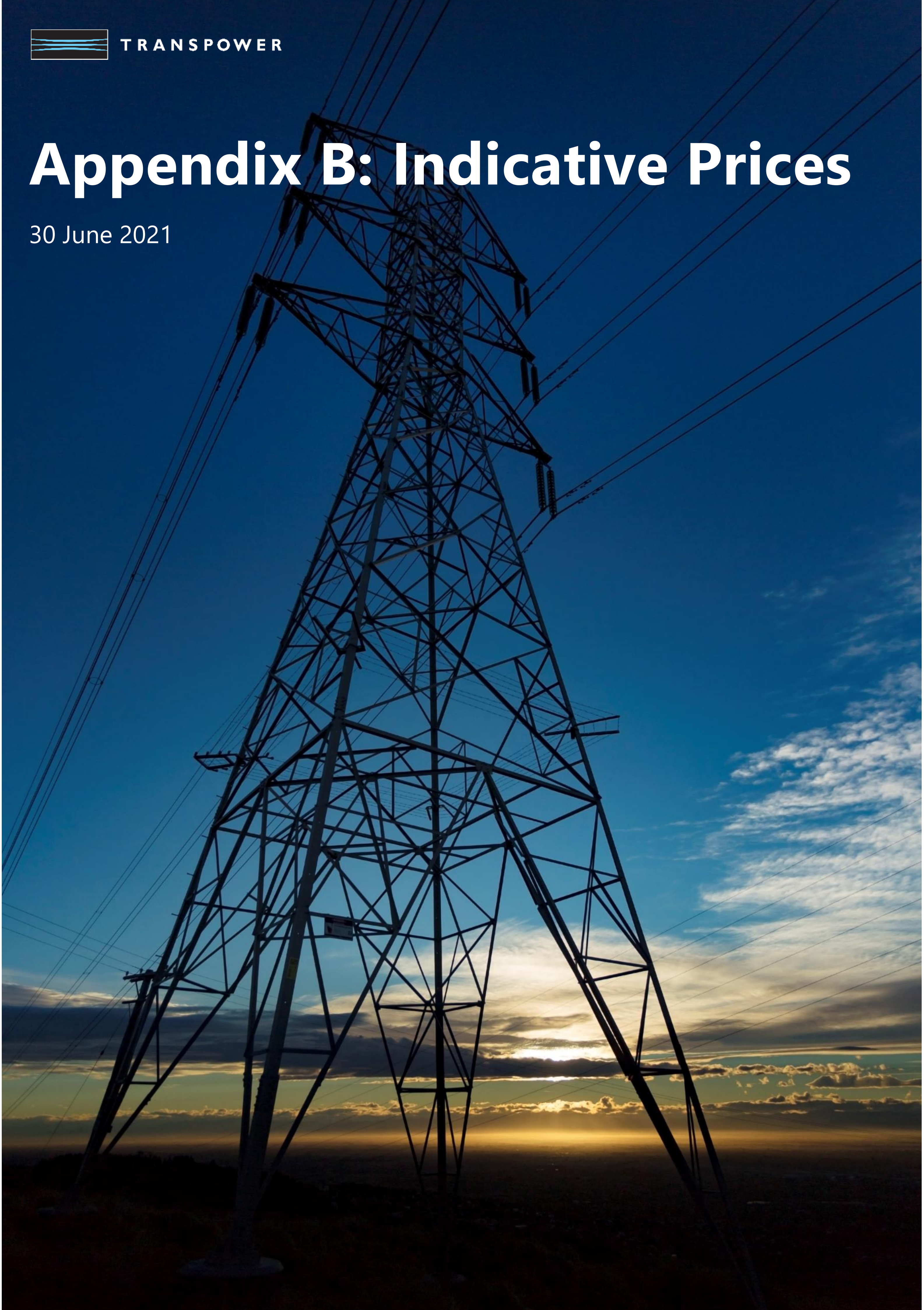
RELEVANT GUIDELINES CLAUSE	PROPOSED DEPARTURE	GUIDELINES/ AUTHORITY INTENT	STATUTORY OBJECTIVE
Clause 40(b) of the Guidelines	**No automatic reallocation in response to reassignment** Our proposal is that reassignment would not, by itself, result in any reallocation of the BBCs for the relevant BBI. Reassignment is a response to the BBI being over-sized compared to forecast future demand for it. Reallocation is not a necessary or appropriate response to over-sizing. ***See Chapter 11: Part G – Reassignment, section 8, for further detail.***	The Authority's intent is that BBCs are fixed-like charges. This is clear from clause 24 of the Guidelines as well as the Authority's Decision Paper at paragraph 9.83. The Guidelines specify in clauses 33, 41 and 42 particular situations in which the BBCs may be reallocated. It would appear out of step with that intent if clause 40(b) of the Guidelines effectively added a reallocation adjustment event of "if something else happens or does not happen". This proposal is consistent with clause 1(b)(iii) of the Guidelines (certainty, including by limiting the need for Transpower to exercise discretion).	The Authority expressly indicated in its 2020 decision that having fixed-like allocations of the BBC promotes efficient investment and the efficient operation of the electricity industry. It noted that this approach aims to balance competing considerations around certainty, efficiency and discouraging inefficient charge avoidance behaviour. Consistent with these comments, Transpower considers that its proposal would better meet the efficiency limb of the Authority's statutory objective than if the proposal were not implemented. ***See Chapter 11: Part G – Reassignment, section 10.1, for further detail.***
		Transitional price cap	
Clauses 50(a) and 50(b) of the Guidelines	**Source of gross energy information** The proposed TPM does not require the gross energy weighting for variable P of the capped load customer's total gross energy to be obtained from the reconciliation manager. This is a departure from the requirements of clauses 50(a) and 50(b) of the Guidelines, which otherwise require this gross energy information to come from the reconciliation manager. For distributor total gross energy information, Transpower proposes using the regulated disclosures for electricity distribution businesses. For other total gross energy information Transpower may use a variety of sources, including the reconciliation manager. ***See Chapter 12: Part H – Transitional Price Cap, section 7.2, for further detail.***	The proposal is not inconsistent with the intent of the Guidelines. The calculation of the customer's notional electricity bill for pricing year 2019 does not change substantively. The departure goes only to the source of the input information. It is also consistent with the principle in clause 1(b) of the Guidelines (practical considerations, particularly costs associated with administering the TPM). As the Authority has pointed out, the reconciliation manager may not have all the data necessary to calculate gross demand or energy (Checkpoint 2A Feedback, paragraph A.9), which this proposal addresses.	The proposal supports the efficiency limb: Without this departure the cost of administering the TPM may increase because Transpower will not be able to use information it already holds or can obtain from alternative, less costly (or costless) sources. ***See Chapter 12: Part H – Transitional Price Cap, section 7.2, for further detail.***
Clause 50(b) of the Guidelines	**Generators in their capacity as direct consumers** Our proposal is to not apply the transitional cap to generators to the extent they are direct consumers. This is a departure from clause 50(b) of the Guidelines. In the proposed TPM, clause 108 provides that the cap applies to *capped customers*, which is defined to exclude generators. The Guidelines would capture generators insofar as they were taking electricity from the grid. However, the proposed TPM excludes generators in all capacities. ***See Chapter 12: Part H – Transitional Price Cap, section 5, for further detail.***	The proposal is not inconsistent with the intent of the Guidelines. In its 2020 Decision, consistent with the reference to limiting "price shocks" in clause (vii) of the Guidelines, the Authority noted the purpose of the transitional cap is to "limit the increase in total electricity bills that would otherwise be caused by implementing a new TPM". Applying the transitional cap to generators in their capacity as direct consumers would go beyond limiting price shocks from the new TPM – it would result in a windfall gain to generators by capping some of their BBCs as well as their residual charges. This would be contrary to the intent of the new regime. The proposal is also consistent with the principle in clause 1(e) of the Guidelines (avoiding discrimination between customers).	The proposal promotes the efficiency and competition limbs of the statutory objective. Large and seemingly unintended wealth transfers in favour of grid-connected generators would create inefficient pricing signals, particularly, in this case, in respect of the pre-2019 BBIs in Schedule 1 of the Guidelines (Appendix A of the proposed TPM). Competitive neutrality between grid connected generators and embedded generators would be compromised, with the former advantaged over the latter. ***See Chapter 12: Part H – Transitional Price Cap, section 7.1, for further detail.***

RELEVANT GUIDELINES CLAUSE	PROPOSED DEPARTURE	GUIDELINES/ AUTHORITY INTENT	STATUTORY OBJECTIVE
	Implementation timeframes		
Clause 66 of the Guidelines	We propose to commence the BBC for a post-2019 BBI from the first pricing year that starts at least six months after the BBI is commissioned, or an earlier pricing year if we determine it is practicable to do so (clause 37(1) of the proposed TPM and paragraph (a) of the definition of "start pricing year"). Our proposal to delay the start of the BBC for a high-value post-2019 BBI until the start of a pricing year is a departure from the wording of clause 66 of the Guidelines. ***See Chapter 6: Part D – BBC covered cost, section 4, for further detail.***	The proposal is not inconsistent with the intent of the Guidelines. Over the life of the BBI the full covered cost of the BBI will still be recovered through its BBC, as required by clause 15 of the Guidelines. We consider the maximum 18-month delay in the start of the BBC is inconsequential in the context of the life of a BBI, which will typically be several decades. The departure is also consistent with the principle in clause 1(b) of the Guidelines (practical considerations, including balancing the benefits of precision against the benefits of simplicity and the costs of compliance).	This approach promotes the efficiency limb of the Authority's statutory objective. The six month (or potentially shorter) period of "clear air" before the start of a pricing year allows the calculation, audit and notification of the new BBC to fit within our normal annual pricing process, which is constrained by our obligation to provide our customers with at least three months' notice of their annual transmission charges. This in turn allows time for our customers to incorporate the new BBC in their own pricing processes. This is more efficient for Transpower, our customers and their customers than going through a separate process to reopen (increase) transmission charges during a pricing year. ***See Chapter 6: Part D – BBC covered cost, section 8, for further detail.***

TRANSPOWER

Appendix B: Indicative Prices

30 June 2021



Contents: Appendix B

1 Introduction

1. This appendix presents the indicative prices Transpower has modelled consistent with its proposed new TPM, and explains the high-level approach and process followed to model them.
2. The indicative prices reflect modelling performed for the 2021/22 pricing year, to provide a comparison with prices under the current TPM. Charges under the proposed TPM are also projected out to the 2034/35 pricing year to indicate how charges may evolve under the TPM proposal. The prices are illustrative only and subject to change as part of TPM finalisation, ongoing verification of underlying data sets, and ongoing evolution of our customer and asset base.

2 Requirements of the Code and the Authority's process decision

3. Clause 12.89(2) of the Electricity Industry Participation Code (the **Code**) states the requirement for Transpower's Proposal to include indicative prices:

> **Form of proposed transmission pricing methodology**
>
> …
>
> (2) **Transpower's** proposed **transmission pricing methodology** must include indicative prices to allow the **Authority** and interested parties to understand the impact of the methodology on **designated transmission customers**.

4. Clause 12.83 of the Code requires the Authority, when publishing new TPM Guidelines, to also publish the process Transpower must follow in developing a TPM consistent with those Guidelines:

> **Authority must publish process and guidelines for development of transmission pricing methodology**
>
> After consideration of submissions in clause 12.82(3), the **Authority** must, as soon as reasonably practicable, **publish**—
>
> (a) the process for the development of the **transmission pricing methodology**; and
>
> (b) any guidelines that **Transpower** must follow in developing the **transmission pricing methodology**.

5. The Authority's process decision under clause 12.83 requires that Transpower's "proposed TPM must include indicative prices to allow its impacts to be understood", and "Transpower's development of the proposed new TPM must include [a step to] calculate indicative prices to show the impact of the proposed TPM on transmission customers."[1]

3 Indicative Pricing Model

6. Transpower has developed a model to produce indicative pricing consistent with its proposed TPM. The model comprises a number of process steps, databases and Excel spreadsheets. The architecture of the Indicative Pricing Model (the **Model**) is shown in Appendix C of this paper. The Excel spreadsheet components of the Model are also provided as part of our TPM proposal package.
7. Our indicative pricing is for the 2021/22 pricing year. This allows our customers to see how their current charges compare (indicatively) to what their charges would have been under the proposed TPM. This approach also aligns with the Guidelines' requirement for all investments in the interconnected grid from July 2019 to be subject to the Benefit-Based Charge (**BBC**).
8. There are three core charge types under the proposed TPM: Connection charges, BBCs and Residual Charges.
9. ***Connection charges:*** The changes we have proposed to connection charges are technical - to fix errors, remove redundancy, reduce ambiguity and achieve better alignment. As such our proposal has no pricing impact on existing price outcomes for most customer level connection charges.[2] Connection charges have been calculated within Transpower's Pricing System (**TPS**) and are an input to the Model.

[1] Refer Part 12 Code, clause 12.83. The Authority's TPM development process decision, including the timeline, is specified in Box 1 of its 2020 Decision (reference document #3), pages 111-112.

[2] Chapter 5 of the TPM Proposal Reasons paper explains the reasons for our proposals for the connection charge. Our indicative pricing for the 2021/22 pricing year has not required any application of our proposals in relation to first mover disadvantage.

10. ***Benefit-based charges:*** The BBC is a new component of the proposed TPM. The BBC applies to all benefit-based investments (**BBIs**). There are three categories of BBIs under the proposed TPM:[3]

    10.1 ***High-value post-2019 BBIs:*** any investment in the interconnected grid, made from July 2019 onwards, for which the capital cost is expected to exceed $20m.[4] The allocation of costs for these 'standard method' BBIs is considered on a case-by-case basis. There were no standard method BBIs for the 2019/20 period covered by our indicative pricing. We have instead developed case studies for standard method investments to help stakeholders better understand the potential impact of the methodology on customer charges. [5]

    10.2 ***Low-value post-2019 BBIs:*** any investment in the interconnected grid, made from July 2019 onwards, which is not a standard method BBI (that is, it is not expected the capital cost will exceed $20m).

    10.3 ***Schedule 1 BBIs:*** seven historic (pre-July 2019), high value investments in the interconnected grid. Schedule 1 of the Guidelines (and Appendix A of the proposed TPM) specify the BBC allocations that apply for recovery of the remaining costs of these 7 BBIs.[6]

11. ***Residual charges:*** the balance of the revenue Transpower (as the grid owner) can recover from its customers in each pricing year is allocated to the residual charge based on the remaining residual revenue after amounts recovered via the benefit based charges and connection charges have been deducted from Transpower's recoverable revenue.

12. The Model also calculates the effect on prices from the ***Transitional Cap***. Transitional cap surcharges are calculated by considering how the proposed TPM will change transmission charges for the pre-July 2019 grid, and the subsequent impact on end consumer delivered electricity bills. It limits our load customers' transmission charge increases due to Schedule 1 benefit-based charges and residual charges relative to the interconnection charge under the current TPM for the pricing year ending 30 April 2020.

13. Our indicative pricing assumes that the two existing prudent discount agreements (Waipori and Aniwhenua/Matahina) and existing notional embedding contract (BlackPoint) have no effect under the new TPM.

4 Process to apply the proposed TPM

14. This section describes the key process steps and calculations applied to determine indicative prices. The descriptions are not exhaustive, and are intended to provide a high-level

---

3 Our proposals for determining the revenue amount to be recovered for each benefit-based investment (BBI), its "covered cost", are explained in Chapter 6 of the TPM Proposal Reasons paper, and the proposed approach to allocation of BBCs to the customers expected to benefit from them in Chapter 7.

4 The Guidelines (reference document #4) set the threshold for application of a BBC standard method, which apply to high-value post-2019 BBIs, by reference to the **base capex threshold** defined in Transpower Capex IM (reference document # 71). The **base capex threshold** is currently $20m.

5 The indicative pricing effect of the BBC Standard method is shown via case studies. Refer Appendix D: *BBC Price-quantity method case study - CUWLP* and Appendix E: *BBC Resiliency method case study - WUNIWM Waikato dynamic reactive device*.

6 Adjustments have been made to Schedule 1 allocations provide for new customer connections and disconnections, and to correct for errors immaterial to indicative prices. These changes are captured in the allocations provided in Appendix A to the proposed TPM drafting.

overview. The section also shows the results of each main process step that make up the indicative price that Transpower's customers would pay under the proposed TPM.

4.1 Recoverable Revenue under the TPM

15. The Commerce Commission (**Commission**) determined that Transpower (as the grid owner) is allowed to recover a maximum allowable revenue (MAR) of **$798.8M** from its customers in pricing year 2021/22. The MAR is called the recoverable revenue under the TPM.
16. Calculate the Connection charge
17. The changes to the existing connection charge are technical and as such there would be no impact on existing price outcomes for most customers for connection charges. Therefore, Transpower's indicative pricing for the connection charge is the same as the actual 2021/22 connection charge for most customers.[7]
18. Total connection charge is **$121.3M or 15%** of total charges for the 2021/22 pricing year.

4.2 Calculate the Benefits-based charge

Calculate the BBC Covered costs

19. The covered cost of a BBI is the share of our recoverable revenue, that is recovered from the beneficiary customers of the BBI through its BBC. Chapter 6 (BBC Covered Cost) explains our proposal for determining the covered cost for each BBI.
20. The components comprising the covered cost of BBIs (or, how the total BBC for each BBI is determined each pricing year) are:
    20.1 Accounting depreciation;
    20.2 Capital charge;
    20.3 Attributed opex; and
    20.4 Tax.
21. For the 2021/22 pricing year, the total covered cost of BBCs is **$228.4M or 29%** of our recoverable revenue.
22. The below table shows BBCs contributing to our indicative prices for the 2021/22 pricing year. The Schedule 1 BBIs make up 95% of total BBCs. The remaining 5% of BBCs recover the cost of many low-value BBIs whose costs are allocated using the proposed BBC 'simple' method (Simple Method BBIs).[8]

---

[7] Adjustments have been made to connection charges for the two existing prudent discount agreements (Waipori and Aniwhenua/Matahina) and existing notional embedding contract (BlackPoint).

[8] For Simple Method BBIs, 'Low Voltage' refers to BBI assets operating at 110kV or lower.

Table 1 Covered cost and its components, for Schedule 1 BBIs and Simple Method BBIs

	Benefits Based Investment	Accounting Depreciation ($000)	Capital charge ($000)	Attributed opex component ($000)	Direct tax implications ($000)	Covered Cost ($000)
Schedule 1	BPE-HAY A&B Reconductoring	1,745	3,256	1,763	(1,196)	5,568
	HVDC	39,150	26,184	49,334	8,225	122,893
	LSI Reliability	712	1,506	720	(78)	2,860
	LSI Renewables	633	1,754	640	(165)	2,862
	North Island Grid Upgrade Project (NIGUP)	13,902	35,739	14,049	4,422	68,112
	WRK-WKM C (Wairakei Ring)	2,035	5,778	2,057	88	9,957
	Upper North Island Dynamic Reactive Support (UNIDRS)	1,436	1,748	1,451	239	4,873
Simple Method	Bay of Plenty Low Voltage	113	78	114	(77)	228
	Cromwell Low Voltage	-	-	-	-	-
	Central North Island Low Voltage	517	485	522	(160)	1,363
	Hawkes Bay High Voltage	26	8	27	(6)	55
	Hawkes Bay Low Voltage	164	74	166	(25)	378
	Lower North Island High Voltage	940	375	950	124	2,389
	Lower South Island High Voltage	243	153	246	8	651
	HVDC Link	281	124	284	(135)	554
	Northland High Voltage	150	70	152	(10)	362
	Northland Low Voltage	15	7	15	(6)	30
	Nelson Marlborough Low Voltage	104	107	105	(59)	257
	Southland Low Voltage	105	82	107	(70)	225
	Timaru Low Voltage	2	1	2	(1)	3
	Upper North Island High Voltage	268	116	271	46	701
	Upper North Island Low Voltage	548	321	554	102	1,525
	Upper South Island High Voltage	141	104	142	(10)	378
	Upper South Island Low Voltage	163	70	165	(69)	329
	Waitaki Low Voltage	2	1	2	(2)	4
	Wellington Low Voltage	576	330	582	64	1,552
	Waikato Low Voltage	124	69	125	(57)	261
	Total	64,096	78,540	74,543	11,190	228,369

23. Figure 1 below shows the contribution to total BBCs of each component comprising the covered cost, on average across all BBIs.

24. The majority of covered cost is made up of three similarly sized cost components:

    24.1 Capital charge (34%),

    24.2 Attributed opex component (33%) and

    24.3 Accounting depreciation (28%).

25. The remaining 5% of covered cost is attributable to direct tax implications, stemming from depreciation tax losses/gains and income tax on the capital charge.:

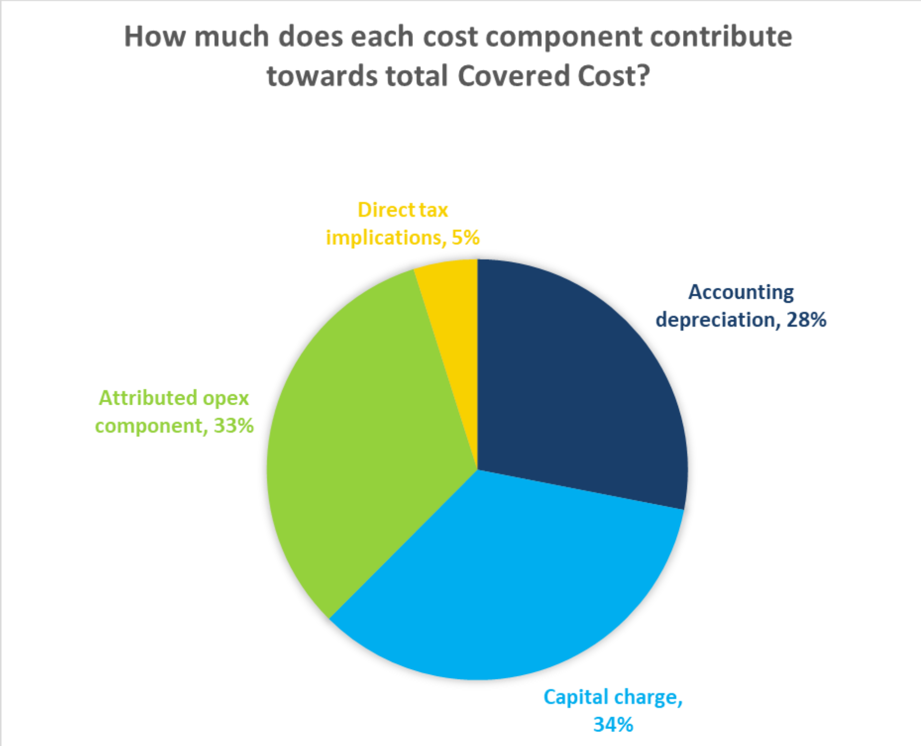


Figure 1 Pie chart to show the contribution of each cost component to covered cost

4.3 Calculate the BBC Schedule 1 allocations

26. Transpower's proposal does not change the methodology that the Authority has used to calculate indicative prices for the seven pre-2019 investments listed in Schedule 1 to the Guidelines. The only adjustments to indicative prices for these BBIs we have made are:

    26.1 to update the covered cost to reflect our proposed approach for attributing opex to BBIs;

    26.2 to incorporate additional assets into the Bunnythorpe-Haywards reconducting project BBI, to recognise the stage of this project that was commissioned during the 2019/20 financial year **($28.4M)**; [9]

    26.3 adjusting allocations to allow for the disconnection of one customer and three new customer connections that occurred over the year to April 2021 and therefore were not considered in the Schedule 1 allocations; and

    26.4 creating allocations for new customers based on comparable customers' allocations, applying the benefit factor method in clause 80(6) of the proposed TPM.

27. The total of BBCs for Schedule 1 investments is **$217.1 or 27%** of our recoverable revenue for the 2021/22 pricing year. These charges are allocated to customers on the basis of the customer allocations provided in Appendix A of the proposed TPM.

4.4 Calculate the BBC Standard Method Allocations

28. There are no new BBIs in the interconnected grid that are >$20M for the 2021/2022 pricing year (i.e. no high-value post-2019 BBIs). Two case studies, provided in Appendix D (Clutha

[9] BPE-HAY was still inflight as at 30 June 2019 with work progressing on the final two sections. The Waikanae section was completed in the 2020/21 Financial Year noting that Indicative Pricing only includes commissioned assets to 30 June 2020.

and Upper Waitaki Lines Project aka CUWLP) and Appendix E (Waikato and Upper North Island Voltage Management aka WUNIVM), have been developed to support understanding of how prices will be determined under the BBC standard methods.

29. Once the new TPM is finalised we will be required to determine allocations and charges for any high-value post-2019 BBIs commissioned after July 2019. At the time of writing we have committed to the following high-value post-2019 BBIs: CUWLP and the Waikato dynamic reactive device (discussed in our case studies), the substation works for the Bombay-Otahuhu major capex project[10], and the HVDC Pole 2 converter transformer refurbishment project.[11]

4.5 Calculate the BBC Simple Method Allocations

30. The proposed TPM would allocate covered costs associated with post-2019 investments in the interconnected grid <$20M by applying the BBC simple method.

31. The proposed simple method is explained in Chapter 7 (BBC Allocations). The simple method is necessarily a mechanical exercise because it is applicable to large number of lower value investments.

32. There are two key steps to calculating the simple method's allocations once the regions have been determined. These are:

33. ***Regional Allocations:*** calculating regional net private benefit (**NPB**) for each connection region in respect of each investment region based on injection and offtake in the connection regions and electricity flows between the connection regions (clause 62 of the proposed TPM). This is performed by running five years of historical market generation, load and branch flow data based on circa 87,000[12]points in time. Total percentage allocation per region, split by customer group (injection and offtake), is shown in the Indicative Pricing workbook that accompanies the Proposal.

34. ***Customer Allocations:*** calculating individual customer NPBs by multiplying the relevant regional NPB by the customers' simple method factors for the relevant connection region, which are calculated from customers' intra-regional allocators for the connection region (clauses 59, 63(10) and 63(11) of the proposed TPM). The individual customer NPBs are then used to calculate customers' BBI customer allocations for the relevant BBI (clause 43(1) of the proposed TPM). Total percentage allocation by customer is broken down in Section 7 of this appendix.

4.6 Allocate BBC Covered Costs

35. Customers' BBCs for the low-value post-2019 investment (<$20M) in the interconnected grid are then calculated by multiplying the covered cost of the BBI by the customers' BBC customer allocations (clause 36(2) of the proposed TPM).

---

10 Bombay-Otahuhu Regional Investigation

11 HVDC Pole 2 Converter Transformer Refurbishment project

12 There were some missing data points at the time of running the Simple Method model for the purposes of the Indicative Prices in this Proposal which impacts the regional allocation factors. Subsequent modelling identified that these datapoints may have resulted in an additional region in the lower South Island. The overall impact of the missing data has been deemed as not material for Indicative Pricing purposes at this time.

4.7 Calculate the Residual charge

36. The residual charge is determined using recoverable revenue less connection and benefit based charges to determine a revenue requirement for the residual charge.
37. The Anytime Maximum Demand Residual (AMDR) for each customer at each location is determined based on historical meter data and aggregated across that Customer's points of connection.
38. The residual charge rate is then determined by dividing the residual revenue requirement by the aggregated AMDR for all customers.
39. The residual charge rate is then applied to each offtake customer as the product of their individual AMDR and the residual charge rate.
40. Total indicative residual charge is **$449.2m or 56%** of total charges for the 2021/22 pricing year.

4.8 Calculate the Transitional Cap

41. The transitional cap is applied to certain load customers' residual charges and BBCs for the historical BBIs listed in Schedule 1 of the Guidelines.
42. The net impact of the transitional cap across all customers is nil as the reductions in some Customer's charges are funded by increased charges from other Customers.
43. The calculation used to determine the transitional cap and the associated explanations are detailed in Chapter 12 (Transitional Cap).
44. The total transitional cap adjustment by customer is broken down in Section 6 of Chapter.12 (Transitional Cap).

5 Indicative prices by charge type 2021/22

45. The chart below shows how the Model has indicatively apportioned Transpower's Maximum Allowable Revenue (MAR) - the recoverable revenue under the TPM- by charge type.

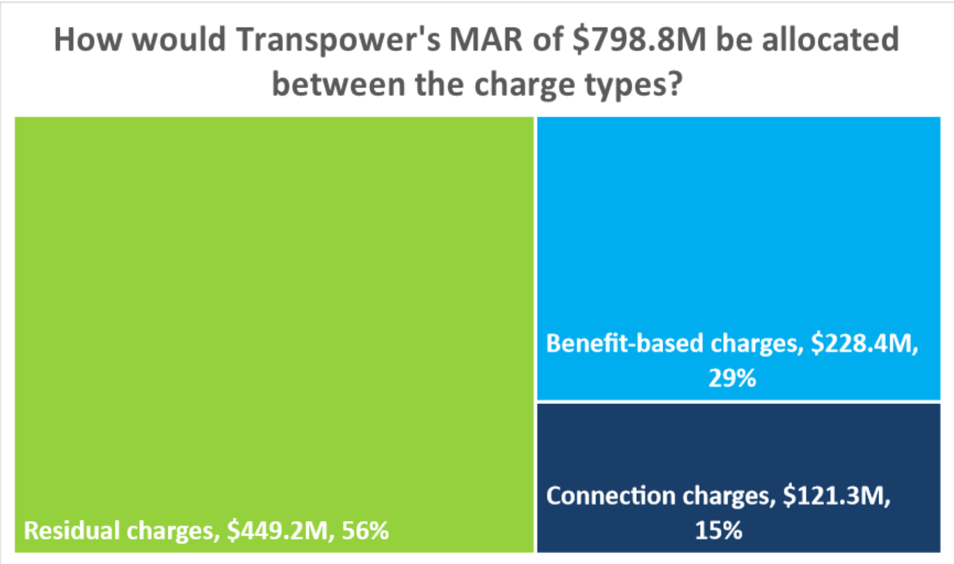


Figure 2 Allocation of Tranpsower's maximum allowable revenue (aka recoverable revenue) between charge types

46. Transpower's MAR of $798.8M is set by the Commission and is recovered using three charge types.
    46.1 The connection charge component is roughly the same as in the current methodology and makes up 15% of recoverable revenue.
    46.2 The new benefits-based charge approach is applied to Schedule 1 and Post-2019 investments, outlined in Section 4, and makes up 29% of recoverable revenue.
    46.3 The remaining 56% of recoverable revenue not captured by these charges is recovered using the residual charge.
47. Figure 3 below shows how the BBC component of the indicative pricing (shown above as 29% of the MAR) is apportioned between different BBIs.

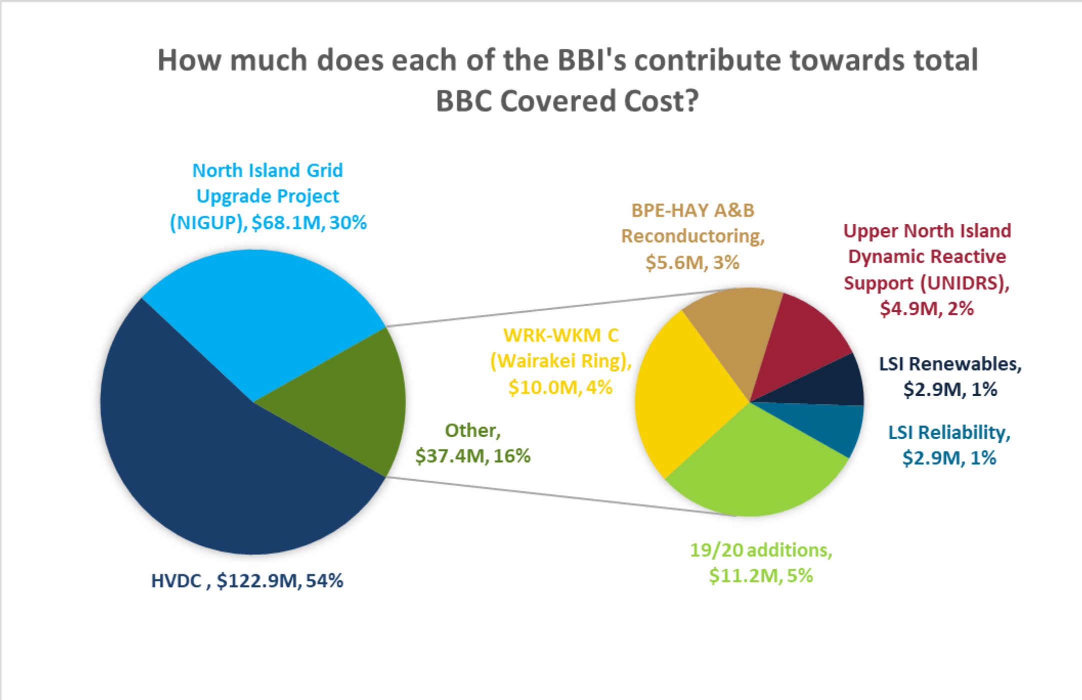


Figure 3 How the 29% of the MAR that comprises BBCs is allocated between BBIs

48. The pie chart above (figure 3) shows how the indicative BBC charge is broken down by each of the 7 historical investments, and the 19/20 new asset additions allocated by applying the simple method.
49. The BBC covered cost is attributed to a number of BBIs. Most of this cost attributable to the HDVC (54%) and the North Island Grid Upgrade Project (30%). The remaining 16% is attributable to the other five Schedule 1 investments and the 19/20 additions.
50. The 19/20 additions segment of the chart captures the BBC allocations made using the simple method and makes up 5% of the total BBC covered cost or only 1.4% of recoverable revenue. This result is due to the simple method BBC applying only to post-2019 investments.

6 Indicative prices per customer 2021/22 by charge type

51. Table 2 below show how Transpower's recoverable revenue is apportioned to each customer by charge type.

Table 2 Transpower's recoverable revenue apportioned to each customer by charge type

Customer name	Ranking	Indicative prices ($m)	% of total charges	% of total charges (cum)	Connection charges	Benefit-based charges	Residual charges	Transitional cap adjustments	Schedule 1 Benefit-based charges	Simple Benefit-based charges
Vector Limited	1	180.1	22.5	22.5	13.2	55.7	108.1	3.2	54.1	1.7
Powerco Limited	2	81.4	10.2	32.7	16.0	11.0	53.2	1.2	10.1	0.9
Meridian Energy Limited	3	66.6	8.3	41.1	16.6	47.7	1.4	0.9	46.5	1.2
Orion New Zealand Limited	4	53.6	6.7	47.8	4.1	8.9	39.6	0.9	8.6	0.3
Wellington Electricity Lines Limited	5	46.3	5.8	53.6	8.2	7.6	29.8	0.7	6.8	0.9
NZ Aluminium Smelters Limited	6	44.7	5.6	59.2	1.3	12.3	30.3	0.8	12.2	0.1
Contact Energy Limited	7	29.9	3.7	62.9	4.2	23.8	1.4	0.5	22.7	1.1
Unison Networks Limited	8	27.0	3.4	66.3	5.6	2.2	18.8	0.4	1.9	0.3
Aurora Energy Limited	9	25.4	3.2	69.5	4.3	2.7	18.1	0.4	2.6	0.0
Powernet Ltd	10	22.3	2.8	72.3	3.8	2.9	15.3	0.4	2.8	0.1
WEL Networks Limited	11	20.0	2.5	74.8	1.7	2.7	15.3	0.3	2.6	0.1
Northpower Limited	12	18.2	2.3	77.1	2.5	6.5	9.0	0.3	6.2	0.3
Genesis Energy Ltd	13	14.5	1.8	78.9	5.0	8.6	0.7	0.2	7.5	1.2
Alpine Energy Ltd	14	12.6	1.6	80.5	2.6	1.6	8.2	0.2	1.6	0.0
Mainpower New Zealand Limited	15	12.1	1.5	82.0	2.9	1.6	7.5	0.2	1.6	0.1
Mercury NZ Limited	16	12.1	1.5	83.5	3.5	6.7	1.8	0.2	6.1	0.6
Counties Power Ltd	17	11.3	1.4	84.9	1.0	3.5	6.7	0.2	3.4	0.1
Network Tasman Limited	18	10.7	1.3	86.2	1.5	1.4	7.7	0.2	1.3	0.1
EA Networks	19	10.7	1.3	87.6	0.3	1.0	9.2	0.2	1.0	0.0
New Zealand Steel Limited	20	9.7	1.2	88.8	2.3	2.7	8.8	(4.0)	2.6	0.1
Electra Limited	21	9.0	1.1	89.9	1.6	1.5	5.8	0.1	1.4	0.1
Horizon Energy Distribution Ltd	22	7.7	1.0	90.9	2.4	0.4	4.8	0.1	0.4	0.0
Waipa Networks Limited	23	6.3	0.8	91.7	1.2	1.2	3.9	0.1	1.1	0.1
The Lines Company Ltd	24	6.1	0.8	92.4	1.4	0.7	3.9	0.1	0.7	0.0
Top Energy Ltd	25	5.9	0.7	93.2	1.0	1.2	3.6	0.1	1.1	0.0
Marlborough Lines Limited	26	5.5	0.7	93.9	0.6	1.0	3.8	0.1	0.9	0.1
Network Waitaki Limited	27	5.3	0.7	94.5	0.9	0.7	3.6	0.1	0.7	0.0
Pan Pac Forest Product Limited	28	4.1	0.5	95.0	1.0	0.8	4.1	(1.8)	0.7	0.0
Eastland Network Limited	29	4.0	0.5	95.5	0.3	0.6	3.1	0.1	0.5	0.1
Westpower Limited	30	3.8	0.5	96.0	0.7	0.2	2.9	(0.0)	0.2	0.0
Norske Skog Tasman Limited	31	3.7	0.5	96.5	1.2	0.5	6.4	(4.3)	0.4	0.1
Winstone Pulp International	32	3.5	0.4	96.9	1.1	0.5	1.9	0.0	0.4	0.0
KiwiRail Holdings Limited	33	3.4	0.4	97.3	2.0	0.3	2.2	(1.0)	0.3	0.0
Nga Awa Purua Joint Venture	34	2.5	0.3	97.7	0.4	1.7	0.3	0.0	1.5	0.2
Centralines Limited	35	2.2	0.3	97.9	0.8	0.4	1.1	0.0	0.3	0.1
Trustpower Limited	36	2.0	0.2	98.2	0.8	1.1	0.0	0.0	1.0	0.1
Scanpower Limited	37	1.7	0.2	98.4	0.6	0.3	0.8	0.0	0.2	0.0
Ngatamariki Geothermal Ltd	38	1.4	0.2	98.6	0.3	1.0	0.0	0.0	0.9	0.1
Buller Electricity Ltd	39	1.4	0.2	98.7	0.5	0.1	1.0	(0.2)	0.1	0.0
OMV New Zealand Production Ltd	40	1.1	0.1	98.9	0.3	0.2	0.6	0.0	0.2	0.0
Todd Generation Taranaki Limited	41	1.0	0.1	99.0	0.1	0.9	0.1	0.0	0.6	0.2
Nelson Electricity Ltd	42	0.9	0.1	99.1	0.1	0.1	0.7	0.0	0.1	0.0
Whareroa Cogeneration Limited	43	0.9	0.1	99.2	0.2	0.1	1.6	(0.9)	0.1	0.0
Methanex New Zealand Ltd	44	0.9	0.1	99.3	0.2	0.1	0.5	0.0	0.1	0.0
Daiken Southland Limited	45	0.8	0.1	99.4	0.2	0.2	0.5	0.0	0.2	0.0
Nova Energy Limited	46	0.7	0.1	99.5	0.3	0.1	0.4	0.0	0.0	0.0
Beach Energy Resources NZ (Holdings) Ltd	47	0.7	0.1	99.6	0.1	0.2	0.5	0.0	0.1	0.0
Southern Generation GP Limited	48	0.7	0.1	99.7	0.2	0.0	0.4	0.0	-	0.0
MEL (West Wind) Limited	49	0.6	0.1	99.8	0.1	0.4	0.1	0.0	0.2	0.2
Mercury SPV Limited	50	0.6	0.1	99.8	0.1	0.4	0.1	0.0	0.2	0.1
Waverley Wind Farm	51	0.4	0.0	99.9	0.1	0.2	0.1	0.0	0.1	0.1
Tararua Wind Power	52	0.3	0.0	99.9	0.1	0.2	0.1	0.0	0.1	0.1
MEL (Te Apiti) Limited	53	0.3	0.0	100.0	0.1	0.2	0.0	0.0	0.1	0.1
Southdown Cogeneration Ltd	54	0.2	0.0	100.0	0.0	0.1	0.1	0.0	0.0	0.0
Southpark Utilities Limited	55	0.0	0.0	100.0	0.0	0.0	0.0	0.0	-	0.0
GTL Energy New Zealand Ltd	56	0.0	0.0	100.0	0.0	0.0	0.0	(0.0)	0.0	0.0
Total		**798.8**			**121.3**	**228.4**	**449.2**	**(0.0)**	**217.1**	**11.2**
Lines Business		591.7	0.74	0.74	79.7	117.5	385.1	9.3	112.1	5.4
Generator		133.6	0.17	0.91	31.8	93.1	6.9	1.8	87.8	5.3
Direct Connect		73.6	0.09	1.00	9.8	17.7	57.2	(11.2)	17.2	0.5
Total		**798.8**			**121.3**	**228.4**	**449.2**	-	**217.1**	**11.2**

52. The three graphs in figure 4 below show the total indicative charge each customer would pay under the new TPM for the 2021/2022 period. A customer’s total charge is shown by the number to the right.

53. Customers are grouped by the quantum of their total charge:

    53.1 charges totalling >$ 40m;

    53.2 charges between $5m – $40m, and

    53.3 charges< $5m.

54. Generally speaking, BBCs are a more significant proportion of generators' total charges compared to Electricity Distribution Businesses and other direct connections (e.g. NZ Aluminium Smelters, New Zealand Steel, KiwiRail Holdings.

55. The majority of customers have small, positive Transitional Cap charges while a few have relatively large negative Transitional Cap charges (e.g. New Zealand Steel, Pan Pac Forest Product, Norske Skog Tasman). These few customer's allocated charge under the new TPM would exceed the transitional caps so their charges are decreased by the amount in the yellow bar and these costs are then distributed amongst the rest of Transpower's customers.

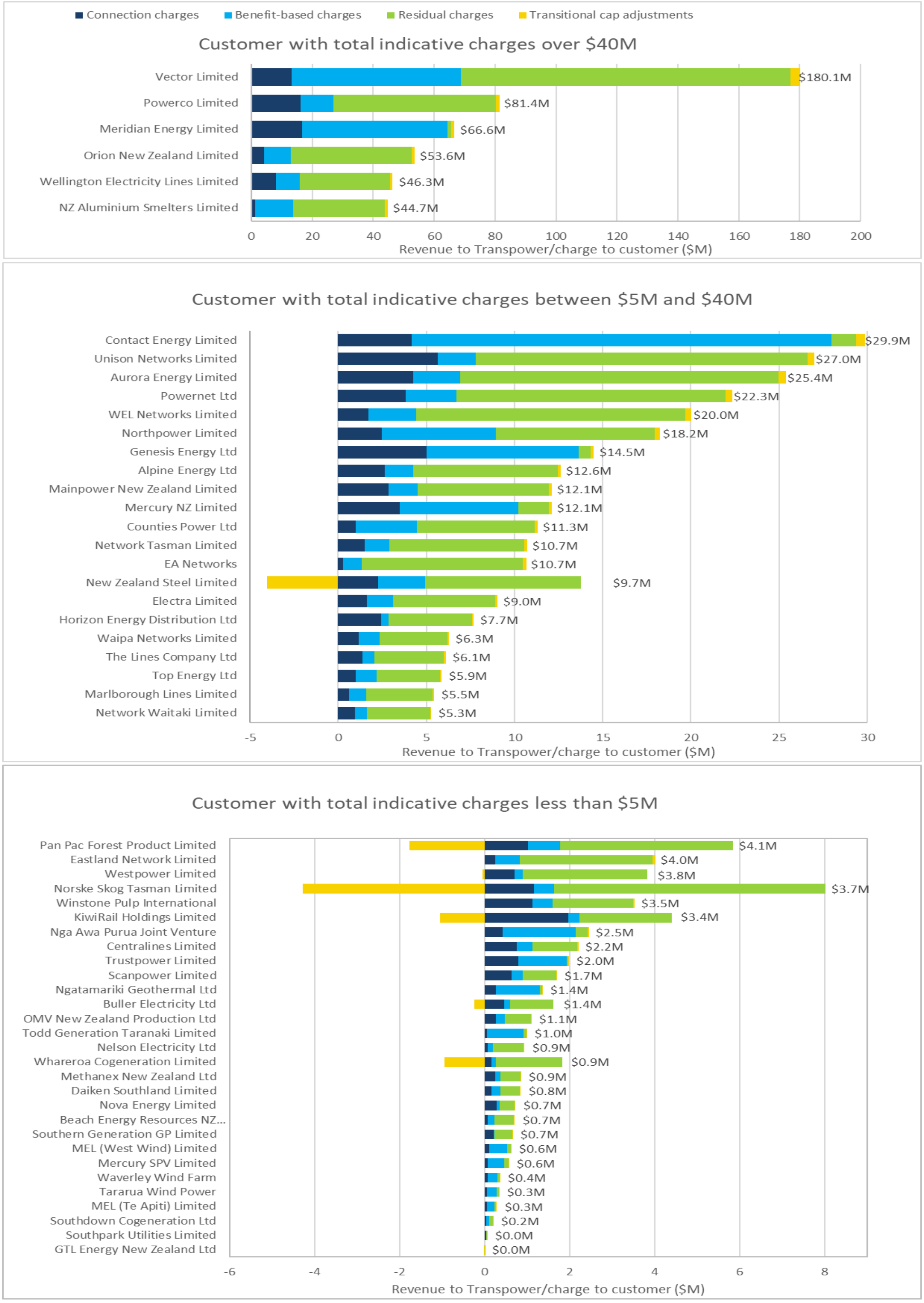


Figure 4 Customer charges by charge type, for charges totalling > 40m, between $5m – 40m, and < $5m.

7 Indicative total charges compared with status quo charges

56. Table 3 and figures 6 and 7 below show how the indicative charges for the 20/21 pricing year compare with the status quo i.e. the charges our customers have received for the current pricing year

Table 3 Indicative total charges compared with the status quo

Customer	Status Quo ($m pa)	Proposed ($m pa)	$ Change ($m pa)	% Change
Alpine Energy Ltd	12.31	12.63	0.32	3%
Aurora Energy Limited	22.12	25.39	3.28	15%
Beach Energy Resources NZ (Holdings) Ltd	0.88	0.70	-0.18	-20%
Buller Electricity Ltd	0.55	1.37	0.82	148%
Centralines Limited	2.65	2.21	-0.45	-17%
Contact Energy Limited	24.56	29.86	5.29	22%
Counties Power Ltd	10.96	11.32	0.36	3%
Daiken Southland Limited	0.79	0.84	0.05	7%
EA Networks	4.56	10.68	6.12	134%
Eastland Network Limited	5.49	4.01	-1.48	-27%
Electra Limited	7.51	9.03	1.53	20%
Genesis Energy Ltd	10.26	14.49	4.23	41%
GTL Energy New Zealand Ltd	0.01	0.01	0.00	75%
Horizon Energy Distribution Ltd	3.49	7.70	4.21	121%
KiwiRail Holdings Limited	2.85	3.36	0.51	18%
Mainpower New Zealand Limited	12.31	12.13	-0.18	-1%
Marlborough Lines Limited	6.66	5.45	-1.20	-18%
MEL (Te Apiti) Limited	0.07	0.27	0.20	278%
MEL (West Wind) Limited	0.12	0.63	0.51	441%
Mercury NZ Limited	3.48	12.10	8.62	248%
Mercury SPV Limited	0.08	0.57	0.49	610%
Meridian Energy Limited	80.94	66.61	-14.33	-18%
Methanex New Zealand Ltd	0.75	0.86	0.11	15%
Nelson Electricity Ltd	1.04	0.94	-0.10	-9%
Network Tasman Limited	11.82	10.73	-1.08	-9%
Network Waitaki Limited	4.00	5.29	1.29	32%
New Zealand Steel Limited	3.13	9.73	6.60	211%
Nga Awa Purua Joint Venture	0.43	2.46	2.03	476%
Ngatamariki Geothermal Ltd	0.26	1.37	1.11	427%
Norske Skog Tasman Limited	1.17	3.74	2.57	220%
Northpower Limited	16.34	18.23	1.89	12%
Nova Energy Limited	0.28	0.72	0.44	159%
NZ Aluminium Smelters Limited	58.32	44.70	-13.62	-23%
OMV New Zealand Production Ltd	1.25	1.10	-0.14	-12%
Orion New Zealand Limited	61.60	53.58	-8.02	-13%
Pan Pac Forest Product Limited	2.77	4.07	1.30	47%
Powerco Limited	92.21	81.40	-10.81	-12%
Powernet Ltd	24.32	22.34	-1.99	-8%
Scanpower Limited	1.92	1.71	-0.21	-11%
Southdown Cogeneration Ltd	0.06	0.20	0.13	211%
Southern Generation GP Limited	0.00	0.65	0.65	-
Southpark Utilities Limited	0.04	0.05	0.00	9%
Tararua Wind Power	0.07	0.34	0.27	409%
The Lines Company Ltd	4.74	6.09	1.36	29%
Todd Generation Taranaki Limited	0.06	1.00	0.94	1443%
Top Energy Ltd	4.93	5.87	0.94	19%
Trustpower Limited	1.91	1.99	0.08	4%
Unison Networks Limited	29.84	27.00	-2.84	-10%
Vector Limited	172.11	180.13	8.02	5%
Waipa Networks Limited	7.69	6.30	-1.39	-18%
Waverley Wind Farm	0.07	0.36	0.29	390%
WEL Networks Limited	19.94	20.03	0.09	0%
Wellington Electricity Lines Limited	54.24	46.32	-7.93	-15%
Westpower Limited	2.04	3.78	1.74	85%
Whareroa Cogeneration Limited	0.17	0.87	0.71	425%
Winstone Pulp International	3.35	3.53	0.18	6%

57. Figures 5 and figure 6 below show the above information is graph form, in dollar (figure 5) and percentage (figure 6) terms

Figure 5 Indicative charges v status quo in dollar terms, for pricing year 20/21 (the current pricing year)

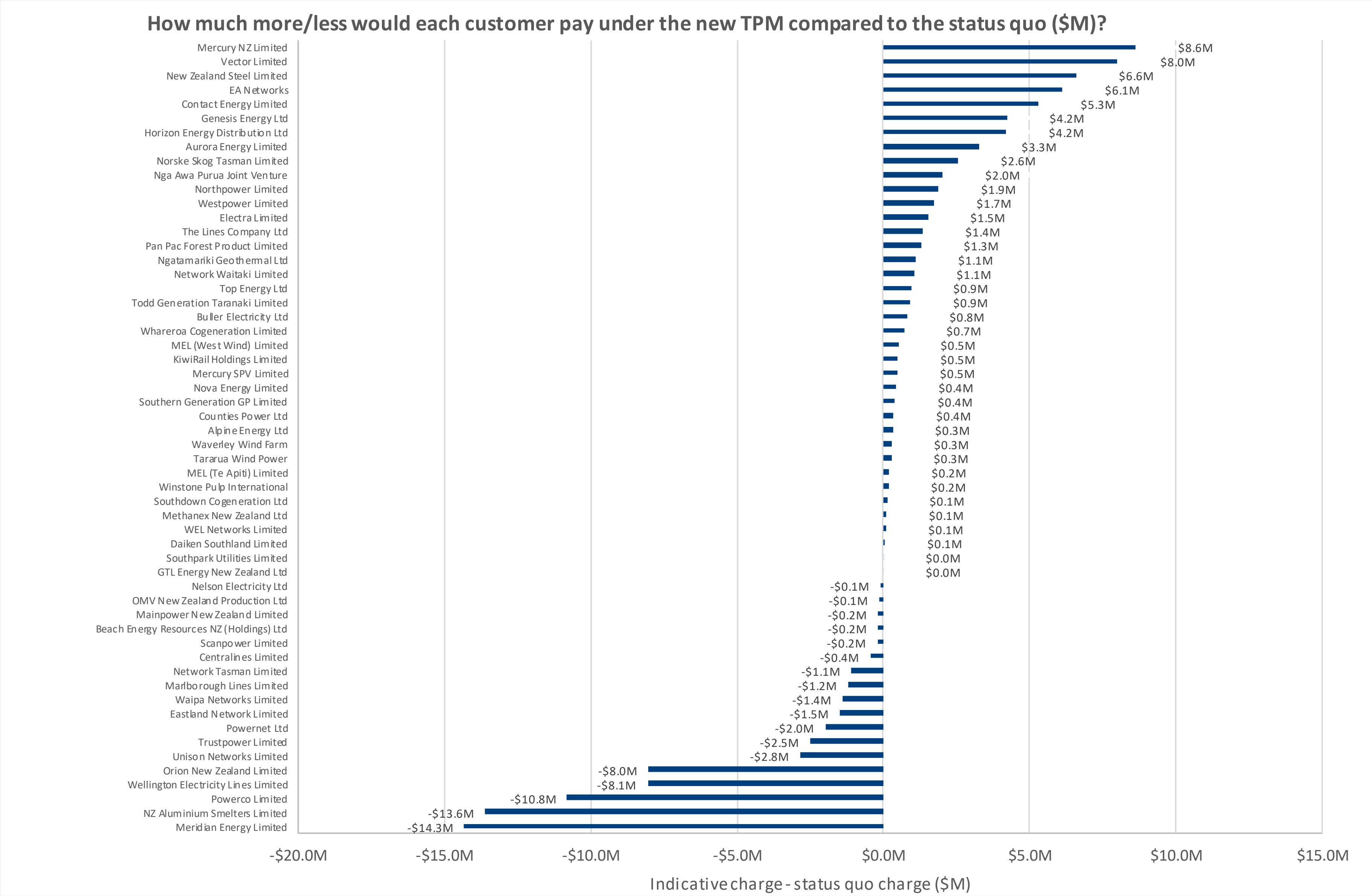
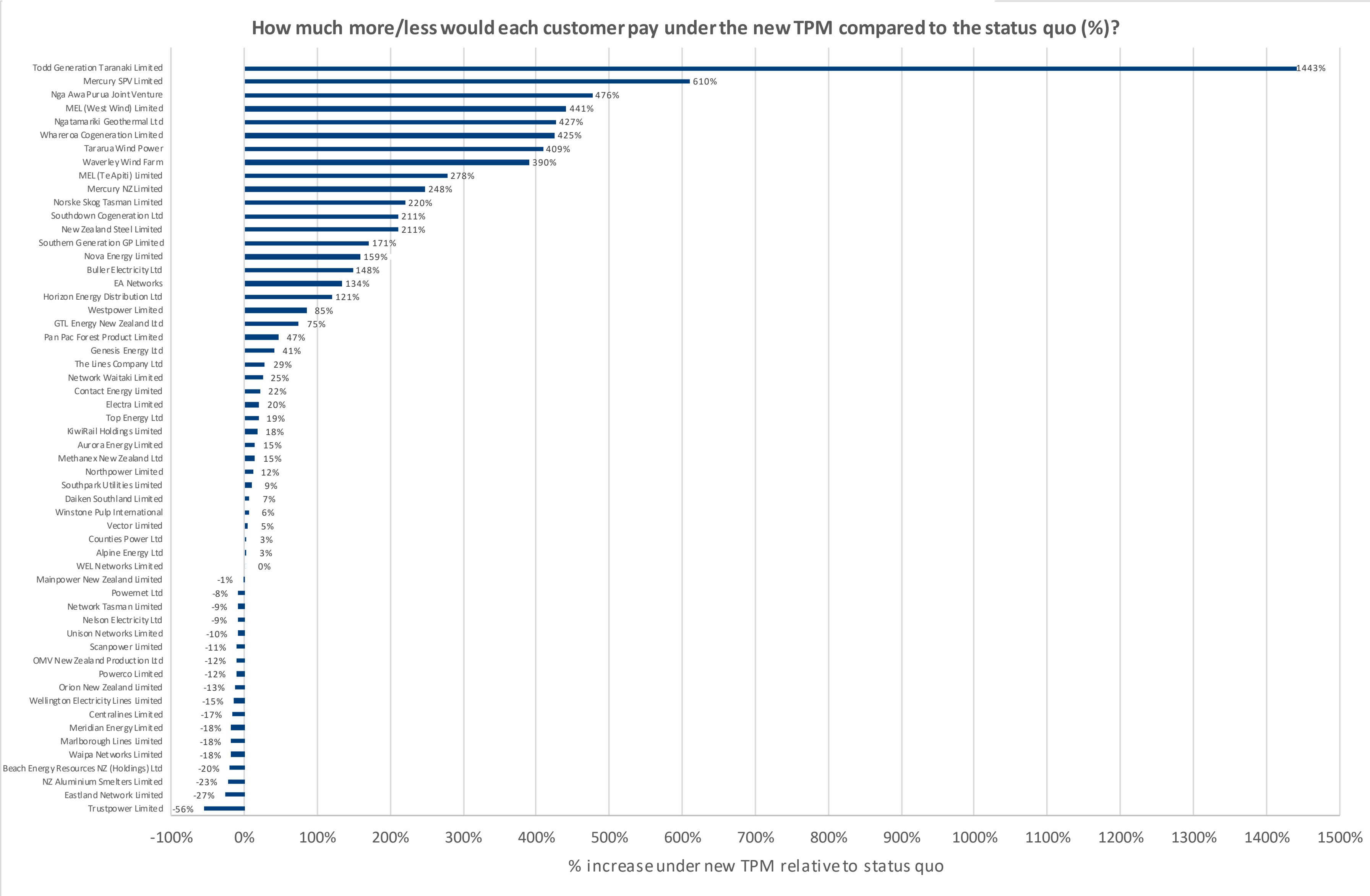


Figure 6 Indicative charges v status quo in percentage terms, for pricing year 20/21 (the current pricing year)



8 Projecting Indicative Prices to 2035

58. In this final section, we attempt to signal how charges may evolve under the TPM proposal. The period for our projection is arbitrary, but sufficient in length to signal the key implications of the TPM, and is set to the 2034/2035 pricing year.
59. Indicative prices for 2021/22 alone cannot reveal the impact of the BBC over time.
60. All other existing investments in the interconnected grid are recovered over time from offtake customers via the residual charge. Eventually these investments will be decommissioned, fully depreciated or replaced as new BBIs. The result will be a gradual reduction in the share of our recoverable revenue collected from load customers as residual charges, offset by a larger attribution to both load and generation customers as BBCs.
61. For the purposes of projecting charges under the new TPM, we have made the following assumptions;
    - 61.1 Investment forecasts are based on Transpower's high-level investment thinking
    - 61.2 Connection charge remains constant as a proportion of Recoverable Revenue
62. For the purposes of projecting indicative prices out to 2034/2035 we have simplified our analysis and assumed post 2020/21 investments in the interconnected grid are depreciated using the same depreciation profile as the 2019/20 year. Actual pricing will be based on the relevant depreciation rate for each type of asset.
63. It is not practicable to project indicative prices to customer level given lack of granular forecast information and very high degrees of uncertainty over the timeline including where we will invest in what and to the benefit of which of our customers.
64. The following projected indicative prices (by charge type) for the period 2023/24 to 2034/35 pricing year are therefore highly uncertain and provided only to demonstrate the directional shift in how our recoverable revenue is likely to be allocated between charge types over time. This is shown in the chart (figure 7) below:
65. As more investments are made and accounted for with BBCs, a growing proportion of recoverable revenue will be recovered through these BBI. This is shown by the growth in the proportions attributed to Post 2020 investment BBC >$20M and <$20M over the forecast period
66. The proportion of recoverable revenue attributable to Schedule 1 Investments will also decline over time as these assets depreciate.

67. As a result of a growing proportion of recoverable revenue being attributed to BBCs, the remaining pool of revenue to be recovered by the residual charge falls, leading to a decline in the proportion of the residual charge over the period.

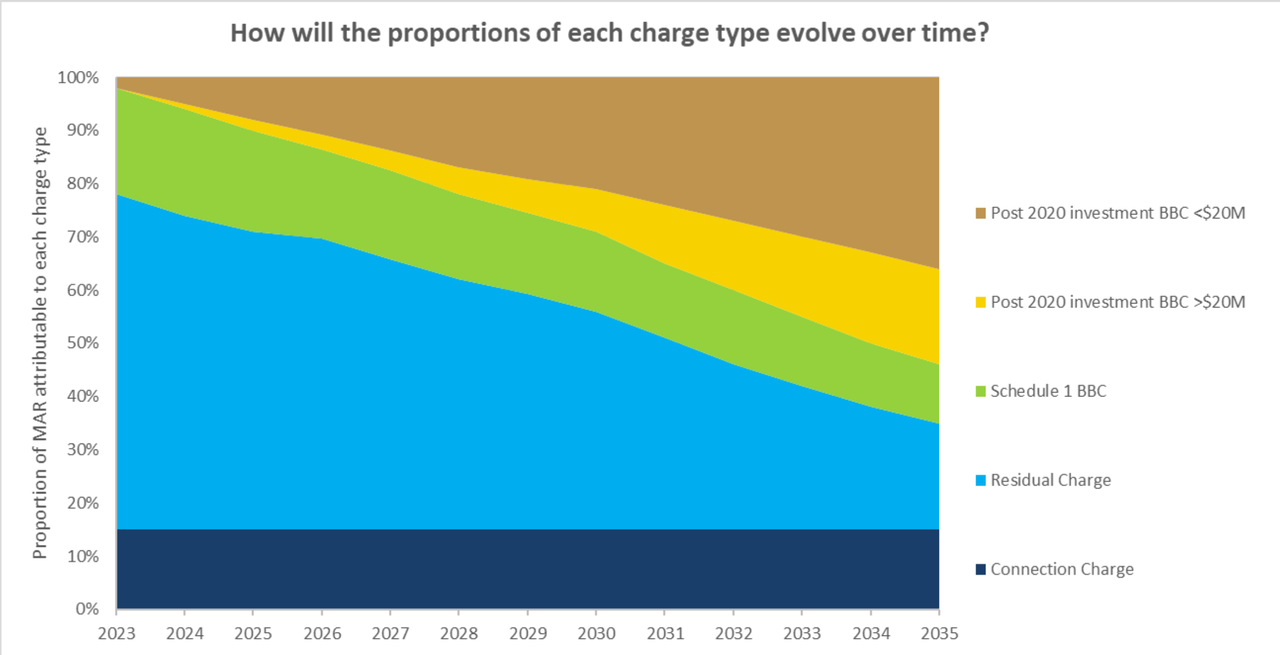


Figure 7 Projection to 2035 of how the proportion of each charge type to recoverable revenue might change

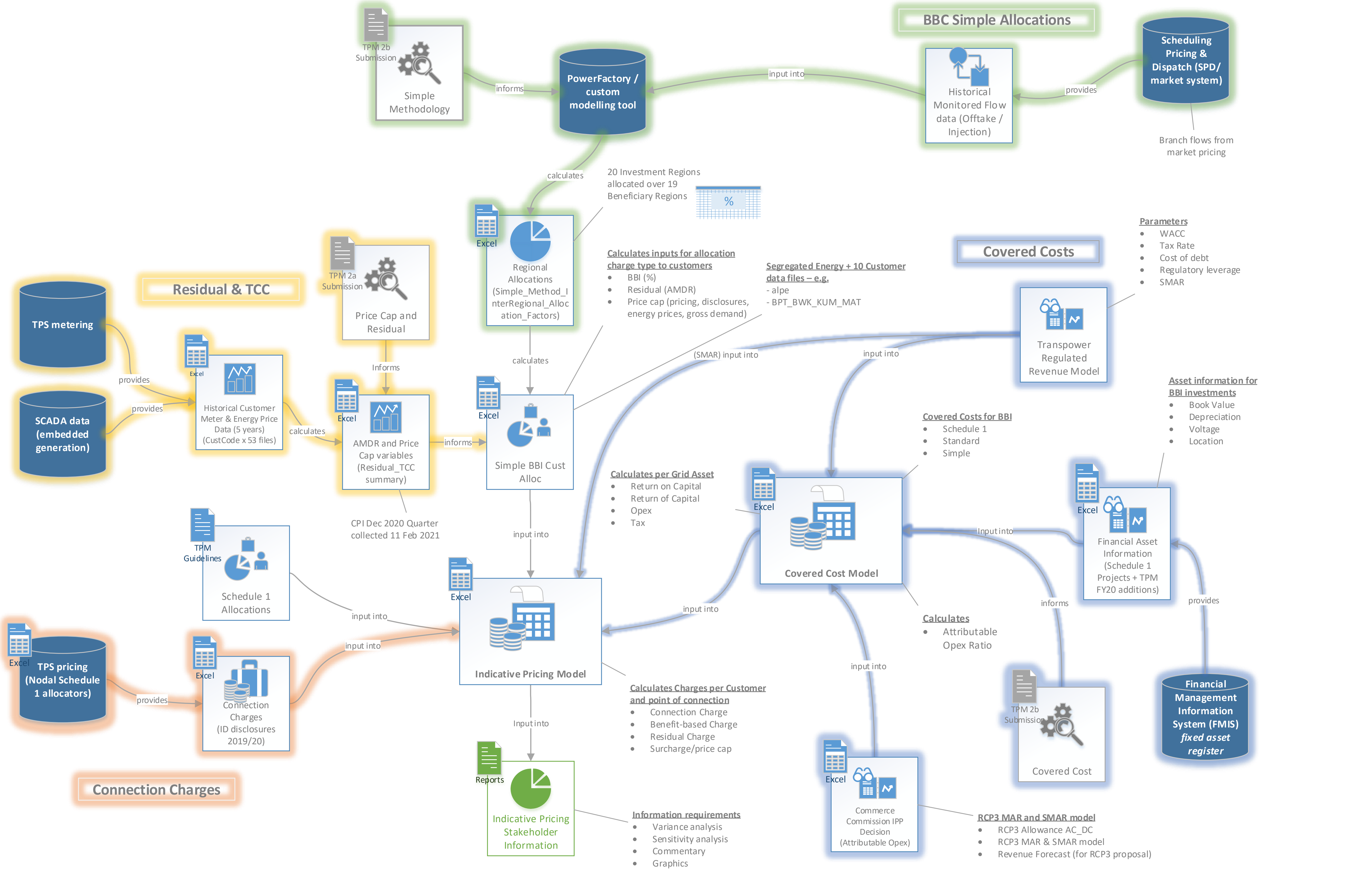
TRANSPOWER

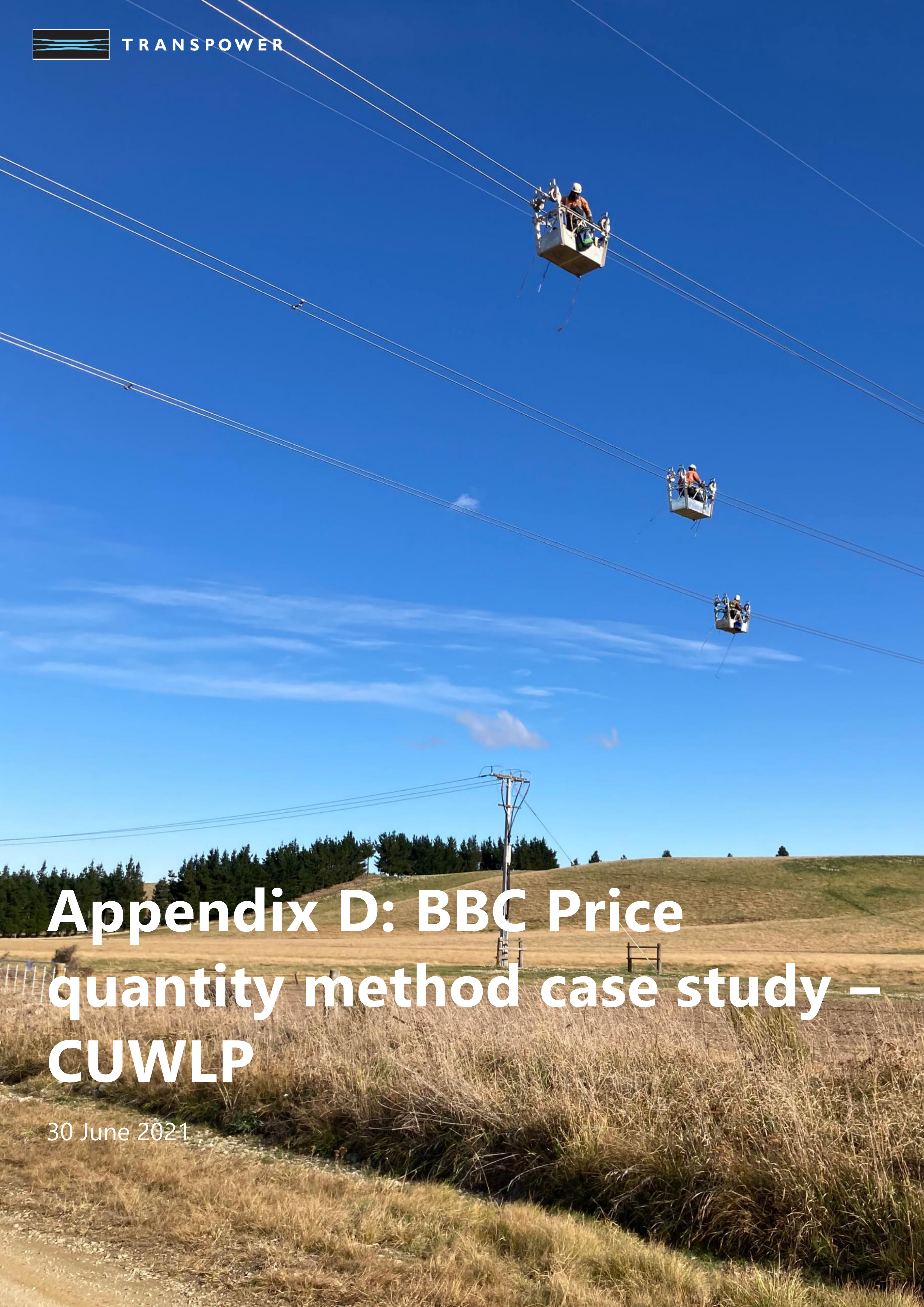
Appendix C: Indicative Pricing Architecture

30 June 2021

Appendix C: Indicative Pricing Architecture

Excludes BBC allocations using standard method (no 2019-2020 BBI require standard method allocation).





TRANSPOWER

Appendix D: BBC Price quantity method case study – CUWLP

30 June 2021

Contents

1 Introduction

1. This appendix presents the results of an indicative pricing case study for the Clutha and Upper Waitaki Lines Project (**CUWLP**). The purpose of this example is to illustrate the application of the price-quantity method to assess market benefits for a high-value post-2019 benefit based investment (**BBI**). The price-quantity method is a benefit-based charge (**BBC**) standard method in the proposed TPM.
2. The proposed TPM will not be formally applied to this project until after the new TPM has been approved and finalised by the Authority. Hence the allocations and pricing in this case study are indicative only and subject to change.
3. We note that the regulatory processes governing investment decisions (the Capex IM) are different from the regulatory processes governing pricing (the TPM). Therefore, this appendix is not intended to explain the background and need for investment in as much detail as is necessary for the investment decision.

2 Background to the project

4. The Clutha Upper Waitaki Lines Project (CUWLP) expenditure was approved by the Electricity Commission in April 2010 as part of the wider LSI Renewables project. As shown in Figure 1 below, the project was to deliver capacity improvements on five transmission circuits, enhancing transmission capacity for both northwards and southwards flows. The capacity improvements primarily motivated to enhance southward flows (for ensuring supply into Lower South Island (**LSI**) during dry periods) were delivered in 2015 and 2016 on the following assets:
    - the Clyde–Roxburgh–1 and 2 circuits, on the ROX-TWZ A line, and
    - the Aviemore–Waitaki and Livingstone–Waitaki circuits, on the AVI-LIV A Line.
5. The LSI renewables project is a Schedule 1 project with cost allocation derived by the Electricity Authority. As specified in the proposed TPM, the cost allocation under

Schedule 1 applies only to the completed works that have delivered the capacity for improved southward flow.[1]

6. The two grid outputs currently under construction (the CULWP project) are primarily to allow for more northward power flows for new generation in the region and accommodate removal of the load of the Tiwai aluminium smelter, which may occur as early as 2024. The grid diagram with already delivered and intended works is shown below (figure 1). The project will deliver increased capacity for northward power flow by:

- a duplexed Roxburgh–Livingstone section of the Roxburgh–Islington 220 kV line and
- a thermal upgrade of the Cromwell–Twizel section of the Roxburgh–Twizel 220 kV line.[2]

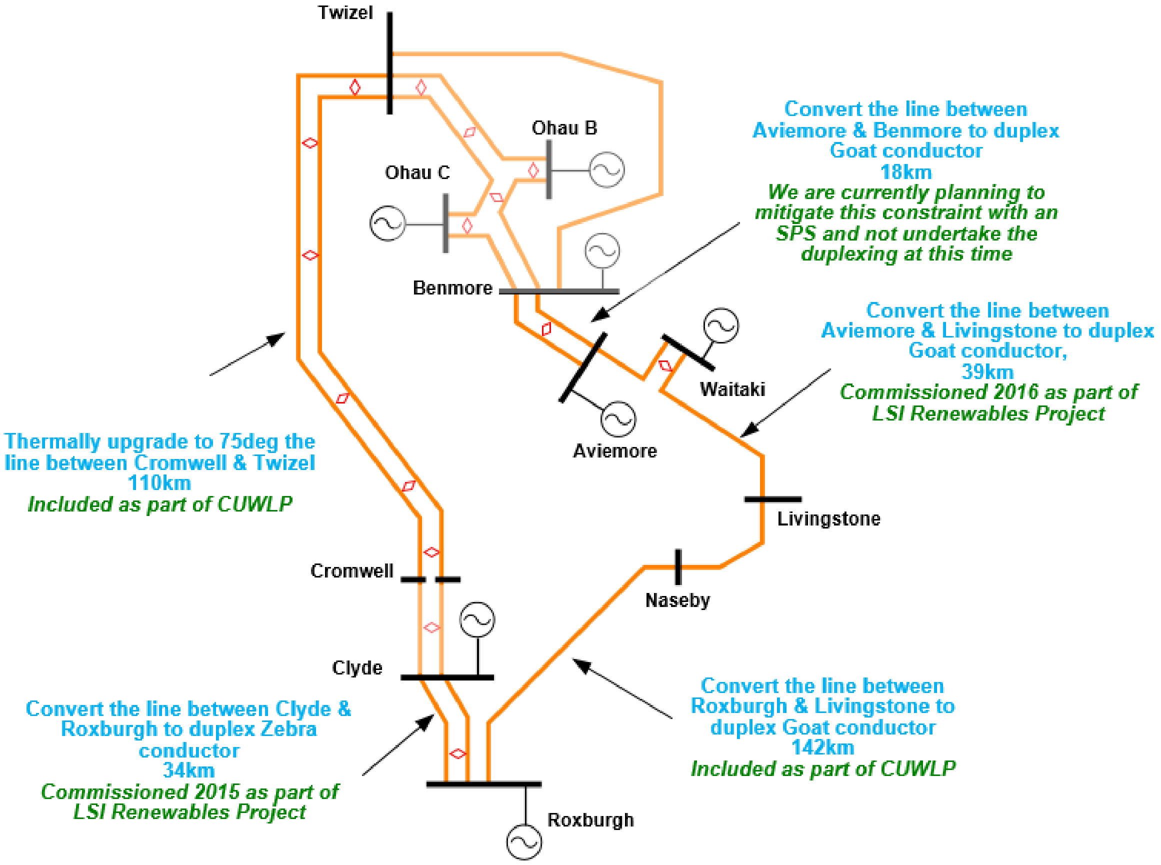


Figure 1 Grid diagram of delivered works (LSI renewables) and intended works (CULWP)

[1] The EA's analysis of the LSI renewable investment for its 2019 issues paper (reference document #1) and its 2020 Decision (reference document #3) was for the CUWLP grid outputs for southward flow (aka LSI renewables under Schedule 1). This case study is for the two northward flow outputs currently under construction.

[2] See our CULWP project page. In our CULWP consultation paper we also indicated we could be duplexing the Aviemore–Benmore circuits, but that duplexing this circuit may not be required after other works are completed. Our assessment is that duplexing the Aviemore–Benmore circuits is not required at this time.

7. The Electricity Commission's approval remains valid because no approval expiry date was specified.[3] We therefore were not required to seek additional approval from the Commerce Commission for the CUWLP investment.
8. In May 2020 we sought feedback from stakeholders to inform our assessment of whether conditions supported Transpower proceeding with the CUWLP investment. We committed to the project in June 2020.[4]

3 Explaining indicative benefit-based charges

9. This section presents the indicative BBC allocations and prices for this case study and describes how these are broadly proportional to expected positive net private benefits (**EPNPB**s), as required by clauses iv and 8 of the Guidelines.
10. The BBC allocations and prices in this case study are only indicative of the prices that will result when the new TPM is eventually applied to CUWLP. The reasons for this include:
    10.1 This case study has been developed primarily to demonstrate how we would apply our proposed TPM to a BBI expected to primarily deliver market benefits, like CUWLP. For the purposes of illustrating an example we have made the simplifying assumption of only modelling two scenarios of future generation and demand. We expect to model ten scenarios when determining actual prices for CUWLP.
    10.2 As noted above, our proposed TPM may be subject to change as the Authority consults on and finalises the TPM.
    10.3 The processes and assumptions used in our modelling under the TPM are still being developed and refined. Our proposed TPM contains all the structural and fundamental features of the TPM methodology. This will be complemented by an assumptions book that will contain assumptions and processes that are common to all BBIs. To finalise the assumptions book we will be consulting our customers, and this will happen prior to calculating allocations under a new TPM.
    10.4 We are yet to consult on the allocations for CUWLP. We note this BBI has been committed before the proposed TPM will come into effect, therefore the assumptions book and resulting final allocations will be consulted on well after the investment decision was made.
11. Some of the key areas where our processes and assumptions are still under development are summarised below
    11.1 How we determine the amount, timing, and location of generation build based on the cost information provided in the Ministry for Business, Innovation, and Employment's (**MBIE**) Energy, Generation and Demand Scenarios (**EDGS**)[5]. Private benefits can be very sensitive to these assumptions, especially when using the market prices directly from our market model without adjustment. As

[3] The Commerce Commission, who now approves all our expenditures, has since legislated for all prospective approvals to have an expiry date.
[4] The May 2020 consultation paper and all submissions and cross-submissions received are available on our webpage.
[5] To inform our generation build assumptions we intend to use future generation cost forecasts from EDGS.

discussed in the Chapter 7 (BBC Allocation), we have mitigated this concern in the proposed TPM, and in this case study, through the use of clause 50A.

11.2 Our treatment of transmission losses. This can affect how often a constraint binds, as well as the relative benefits between generation and load. There are conflicts between precision and practicality that we need to further assess before determining an approach that strikes the right balance.

11.3 The long-run cost of self-supply. The long-run cost of self-supply acts as a cap on the market price loads will receive in our model, but it is also a key parameter used by the model to determine the optimal use of hydro generation. It is possible the price-cap may not best serve both purposes in all situations and we need to investigate other options for achieving realistic hydro use while representing the long-run cost of self-supply for the purpose of calculating consumer benefits.

12. Section 3.1 below presents the indicative BBC prices for this case study. In applying the TPM to this this case study we have drawn the following conclusions and observations (Sections 3.2 to 3.8 respectively):

- Benefits are primarily to generation upstream and load downstream of constraints
- Relative benefits depend on exposure to the transmission constraint
- Beneficiaries differ between scenarios
- Benefits depend on inflows, not peak periods
- Benefits change over time
- Indicative and final prices will be sensitive to input assumptions
- We consider these allocations are broadly proportionate to EPNPB.

3.1 Indicative prices for CUWLP

13. Allocations for BBIs are based on net benefits, considering generation and load, at locations where customers are expected to receive positive net benefits.

14. The indicative allocations and prices for this case study are shown below, in table 1, for the 2030 pricing year (prices to be paid between April 2030 and March 2031), which is when we expect the covered cost (the annual BBC across all customers) for CUWLP to peak.[6]

[6] Note, the TPM does not impact the total revenue Transpower recovers, and therefore the $2.7m difference between the total charges attributed to the BBI under the existing and proposed TPM is a difference in attribution of charges, not a difference in total charges/revenue.

Table 1 CUWLP benefit based investment: allocations and charges

Customer	RCPD allocation	RCPD charge	BBC allocation	BBC charge
Alpine Energy	1.64%	$111,746	2.02%	$191,638
Buller Electricity	0.09%	$6,391	0.10%	$9,715
Centralines	0.32%	$22,032	0.30%	$28,115
Counties Power	1.71%	$116,303	1.43%	$135,811
Contact Energy	0.01%	$682	9.18%	$872,254
Aurora Energy	3.01%	$204,448	-	-
Electricity Ashburton	0.73%	$49,649	1.24%	$117,871
Eastland Energy	0.90%	$61,096	0.74%	$69,858
Genesis Power	0.00%	$8	-	-
Electra	1.01%	$68,555	0.66%	$62,983
Horizon Energy	0.18%	$12,134	0.92%	$87,546
Whareroa Cogen	-	-	-	-
Beach Energy Resources	0.14%	$9,433	0.15%	$14,593
Marlborough Lines	1.04%	$70,644	0.99%	$93,616
MEL (Te Apiti) Ltd	0.00%	$110	-	-
MEL (West Wind) Ltd	0.00%	$182	-	-
Meridian Energy	0.01%	$807	12.26%	$1,164,455
Methanex NZ	0.09%	$5,876	0.12%	$11,808
Mainpower	1.62%	$110,053	1.59%	$151,030
Mercury NZ Ltd	-	-	-	-
Mercury SVP Ltd	-	-	-	-
Nga Awa Purua Joint Venture	-	-	-	-
Nelson Electricity	0.16%	$11,188	0.26%	$24,700
Northpower	2.38%	$161,819	2.70%	$256,512
Ngatamariki Geothermal	-	-	-	-
NZ Aluminium Smelters Ltd	9.78%	$665,003	5.37%	$510,287
BHP NZ Steel	0.14%	$9,847	1.02%	$97,327
OMV NZ Production Ltd	0.17%	$11,431	0.20%	$18,952
Orion	9.85%	$669,982	8.33%	$791,433
Pan Pac Forest Products	0.30%	$20,424	1.00%	$94,536
Powerco	13.06%	$888,058	10.63%	$1,010,184
Powernet	3.48%	$236,868	0.40%	$37,753
Daiken Southland Ltd	0.11%	$7,282	-	-
Scanpower	0.22%	$14,928	0.21%	$19,696
Southdown Cogeneration	0.00%	$206	0.00%	$339
Southpark Corporation	0.00%	$54	0.00%	$114
Norske Skog Tasman	-	-	-	-
Resolution Developments Ltd	0.00%	$8	-	-

Customer	RCPD allocation	RCPD charge	BBC allocation	BBC charge
Southern Generation	-	-	-	-
Tararua Wind Power Ltd	0.00%	$66	-	-
Network Tasman	1.77%	$120,158	1.58%	$149,833
Nova Energy	-	-	-	-
Todd Generation Taranaki Ltd	0.00%	$62	0.08%	$7,426
Top Energy	0.68%	$45,921	-	-
KiwiRail Holdings Ltd	0.15%	$10,255	0.12%	$11,418
Trustpower Generation	0.00%	$1	0.30%	$28,812
Wellington Electricity	7.90%	$536,941	5.68%	$539,247
Unison Networks	4.15%	$282,058	3.27%	$310,738
Vector	27.25%	$1,852,890	21.55%	$2,047,183
Waipa Networks	1.12%	$76,026	1.02%	$97,029
Network Waitaki	0.53%	$35,918	0.68%	$64,137
Waverly Wind Farm Ltd	-	-	-	-
WEL Energy	3.12%	$212,269	2.43%	$230,594
Winstone Pulp International	0.38%	$25,818	0.50%	$47,283
Westpower	0.22%	$15,109	0.34%	$32,107
The Lines Company	0.58%	$39,261	0.64%	$61,068

15. The benefits were first determined at a regional group level and then apportioned to customers in the group based on their historical injection and offtake over a 5 year period as required under the TPM.

16. The groups were determined by identifying 5 positive beneficiary groups according to customers in a region who receive similar benefits to each other: LSI generation, industrial and other load in the rest of the country, North Island peaking generation, and Tiwai load. The breakdown between these groups is shown below.

Table 2 CULWP Beneficiary groups

Region	Sub-group	Allocation
Lower South Island	Direct connect gen	21.73%
	Tiwai load	5.37%
Rest of country	Direct connect peakers	0.08%
	Direct connect industrial	3.38%
	All other offtake	69.44%

3.2 Benefits are primarily to generation upstream and load downstream of constraints

17. The indicative allocations and prices in the table above are in proportion to our estimate of EPNPBs.
18. CUWLP provides benefits primarily by alleviating, or preventing, transmission constraints from binding.
19. If power is flowing from region A to region B via a transmission line, region A is exporting electricity because it is generating more than it is consuming, while region B is importing because it is consuming more than it is generating.
20. As illustrated in the diagrams below, when a transmission constraint binds in the wholesale electricity market, prices upstream of the constraint fall, and prices downstream rise. The price represents the cost of supplying the next MW of load at the location. When there are no constraints binding, ignoring the effect of losses, prices across the country are equal as the next MW of load at any location can be supplied by the generator with the cheapest uncleared offer. When a constraint binds, upstream generation with lower offer prices is constrained down/off, meaning the next MW of load at any upstream node can be supplied by this lower cost generation, resulting in lower prices upstream of the constraint. Conversely, downstream generation with higher offer prices is constrained up/on, and the next MW of load for downstream nodes must come from this higher-cost downstream generation, resulting in higher prices.

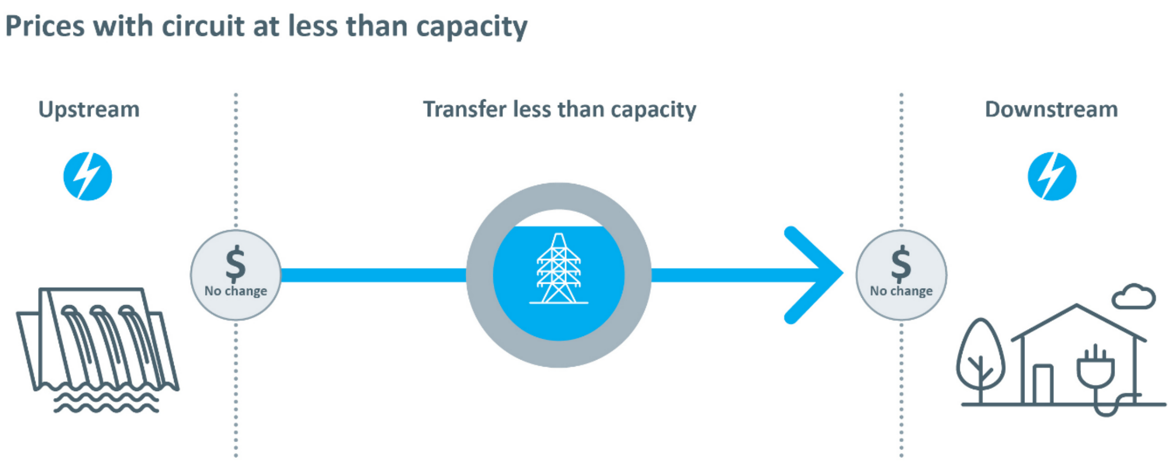


Figure 2 Prices with circuit at less than capacity

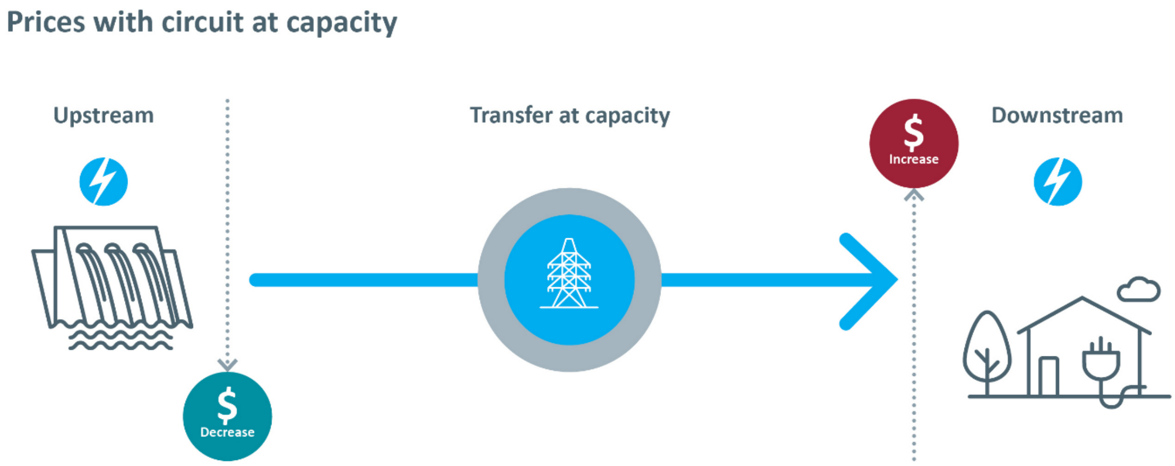


Figure 3 Prices with circuit at capacity

21. By alleviating transmission constraints, CUWLP is expected to deliver private benefits to load downstream, and generation upstream, of the constraint. This is because downstream load doesn't have to pay the elevated energy prices due to the constraint, and upstream generation isn't getting paid suppressed energy prices due to the constraint. Similarly, load will disbenefit in the region where generation benefits, and vice versa.
22. Upstream generation also benefits by being unconstrained from producing higher quantities.
23. Without CUWLP, there can be significant constraints on export of energy out of LSI, and constraints on import of energy into LSI, depending on the climate and season, and whether Tiwai stays or Tiwai leaves.
24. The LSI region has significant hydro generation, with controlled storage. It also has significant load as it contains the Tiwai aluminium smelter.
25. If Tiwai leaves, there will be a significant increase in how much energy LSI generators can export, and without CUWLP the export constraints will frequently bind. Alleviating the export constraint benefits LSI generation (upstream generation) and load in the rest of the country (downstream load).
26. If Tiwai stays, without CUWLP the export constraint will bind during wet periods when there are significant inflows into the LSI hydro storage lakes (noting storage at these lakes is limited), and the import constraints will bind during dry periods when storage is low. Alleviating the import constraint benefits LSI load and generation in the rest of the country.
27. Considering the benefits and disbenefits due to both import and export constraints, and weighting the *Tiwai stays* and *Tiwai leaves* scenarios equally, the beneficiaries expected to have positive net private benefits include LSI generation, load in the rest of the country, North Island peaking generation, and load in the LSI including Tiwai. Based on the scenarios in this case study, LSI loads other than Tiwai, and other generation in the rest of the country, are expected to disbenefit from CUWLP more than they benefit (i.e. negative net private benefits).

3.3 Relative benefits depend on exposure to the transmission constraint

28. The relative benefits between customers depend on their exposure to the constraint – i.e. how often do the constraints that benefit and disbenefit a customer bind, and how much is that customer generating or consuming at those times. For example, all else equal, benefits for most loads will increase over time as their load grows, but benefits for industrial customers will not as generally industrial demand is assumed to be static over time.
29. Under the TPM we estimate total benefits for a group of beneficiaries and allocate these to the individual customers based on historical offtake or injection.
30. Direct connect industrial customers have therefore been grouped separately so they don't pay a share of the benefits attributable to demand growth of other customers.

3.4 Beneficiaries differ between scenarios

31. For this indicative pricing case study, we have modelled two scenarios, both based on the 'Disruptive' EDGS scenario. The scenarios - called *Tiwai leaves* and *Tiwai stays* - differ in that *Tiwai leaves* assumes Tiwai exits at the end of 2024, and the *Tiwai stays* assumes Tiwai remains indefinitely. Each scenario is simulated between 2023 and 2040 and across 86 historical hydrological sequences, with the results shown as the mean of these hydro sequences. For final pricing we intend to model up to five supply and demand scenarios based on the forecast demand and generation costs from MBIE's EDGS, once each with a *Tiwai leaves* assumption and a *Tiwai stays* assumption. See Section 4.7 for more information about the scenarios we have used in this case study.
32. We have chosen to model both of these scenarios as we consider both are credible scenarios and because the benefits and beneficiaries differ significantly between them. We have chosen to weight these scenarios 50-50% in determining allocations as we have no reason to believe a different weighting is more justifiable.
33. The benefits and disbenefits differ per scenario as the beneficiaries' exposure to export and import constraints differ per scenario and different beneficiaries benefit differently from each constraint.
34. In the *Tiwai stays* scenario, the import constraint is expected to bind more often than the export constraint. In the *Tiwai leaves* scenario, the export constraint is expected to bind frequently. Figure 4 shows the proportion of binding constraints for the two scenarios. On average across the two scenarios, the export constraint binds significantly more often.

35. Load beneficiaries outside of LSI are positive net beneficiaries because the export constraint binds more often across the two scenarios.
36. Most generation customers outside of LSI are expected to have negative net benefits because they are disbeneficiaries of the export constraint, which binds more often on average across scenarios.
37. Peak generation in the North Island is a positive net beneficiary because it is exposed more often to the import constraint than the export constraint:
    37.1 LSI generation is being used more when the export constraint is binding compared to when the import constraint is binding, meaning less other generation is required.
    37.2 The import constraint binds more often in winter when peaking plant is more likely to be needed to meet a higher total demand.
    37.3 If Tiwai leaves, there will be an excess of existing generation to meet demand, so peak plant will be required less in general, including when the export constraint is binding (which is often).

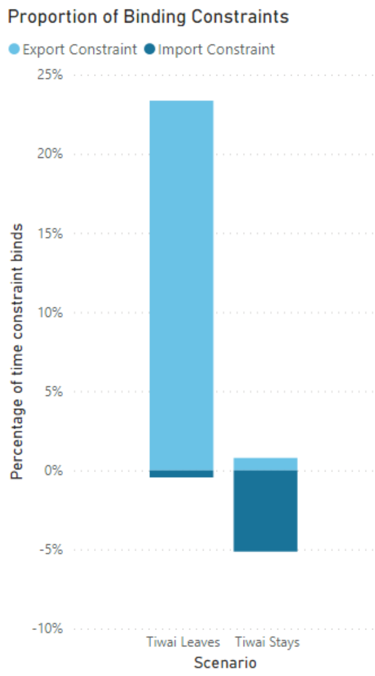


Figure 4 Proportion of binding constraints

38. LSI generators are positive beneficiaries because:
    - the export constraint binds more often on average across the two scenarios
    - they generate large amounts at the time the export constraints bind
    - they can generate more when unconstrained
    - they are generating low amounts when the import constraints binds.
39. LSI loads, apart from Tiwai, are net disbeneficiaries because the export constraint binds more often across the two scenarios.
40. Tiwai benefits on average across scenarios because only the *Tiwai stays* scenario is used to calculate Tiwai's allocations (according to clause 46(3) of the proposed TPM), and because the import constraint binds more often than the export constraint in the *Tiwai stays* scenario.

3.5 Benefits depend on inflows, not peak periods

41. The benefits depend more on inflows into hydro lakes than on seasonal or intra-week peak demand. When the constraints bind, they tend to bind at all load levels in a given week[7] and the export constraint binds more often in late spring and summer when load is at its lowest.

7 To reduce solve time, our modelling uses weekly time steps and breaks these into different load levels to represent the range of hourly loads forecast for that week. The modelling always includes a load block representing the peak hour for the week. Constraints bound similarly across different load blocks.

42. The export constraint binds mostly during and following high inflow events into the LSI hydro storage lakes. During inflow events river flows increase whether or not controlled storage is being used, because there are significant inflows in the region coming from uncontrolled sources, in particular steady flows come from Lake Wanaka and Lake Wakatipu. Generators have limited discretion to use these flows during intra-day peak periods in preference to off-peak. Following inflow events storage levels will have increased, increasing the risk of the storage lakes reaching their capacity and excess water needing to be spilled if further inflow events were to occur. To avoid this spill, generators will generate more, causing the export constraint to bind. Without the CUWLP investment, transmission capacity is not able to export all this generation from the LSI into the rest of the market, and the stored water will be spilled to prevent the storage lakes from exceeding their upper limits.

43. In the *Tiwai stays* scenario, the import constraint binds during times of low inflows when the risk of running LSI hydro storage dry is high. Dry spells can last for significant periods of time and during these times the constraint is slightly less likely to bind at peak periods because that is when the LSI hydro is more likely to be needed.

44. Wet spells and dry spells vary per season and from year to year depending on the prevailing climate pattern.

45. How much hydro generation is used in the market depends on the risk of running out versus the risk of spill, which depends on storage levels and the expectation of future inflows:

    45.1 Storage levels depend on the sequence of inflows. Our modelling simulates the market under different inflow sequences based on the inflows that occurred historically, as a representation of the inflow patterns that may occur in the future. The expected benefits are based on the average benefits simulated across all scenarios.

    45.2 The expectation of future inflows depends on the season.

46. The graphs in Figure 5 below show how often the constraint binds depending on inflow scenario. The scenarios we modelled were 86 historical inflow years from 1932 to 2017, inclusive.

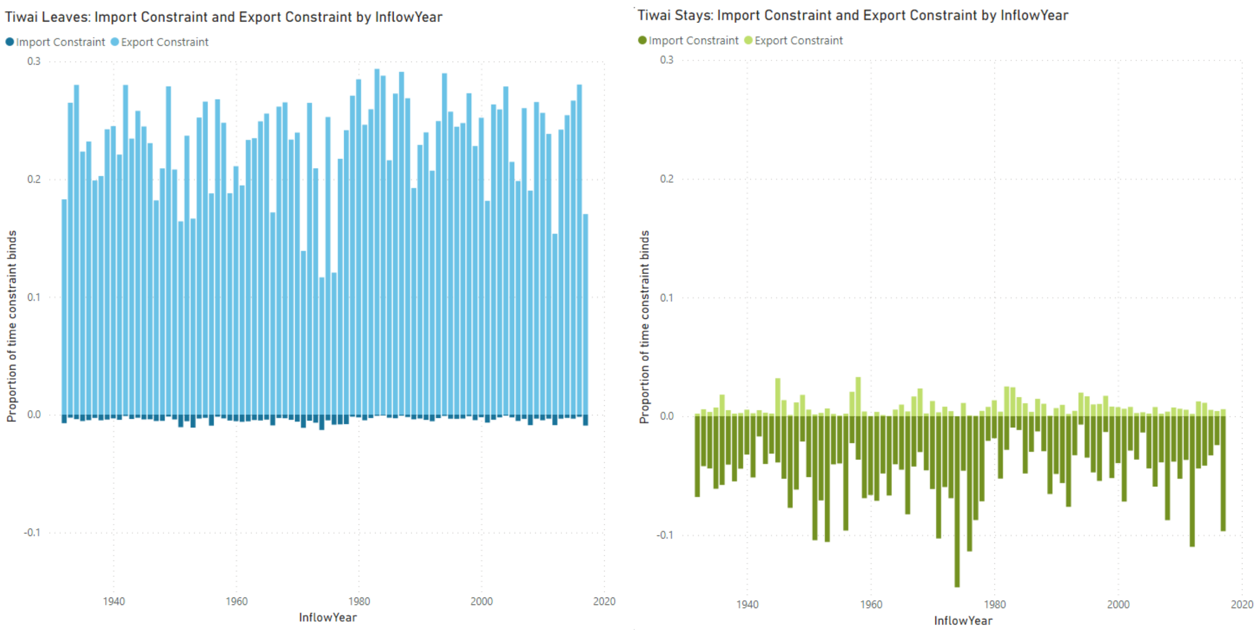


Figure 5 Graphs showing binding constraints with inflows for scenarios Tiwai leaves (left) and Tiwai stays (right)

47. The graphs in Figure 6 below show how often the constraint binds each month, in each scenario. This binding constraint is measured as the proportion of all hours in the month on average across all the inflow scenarios

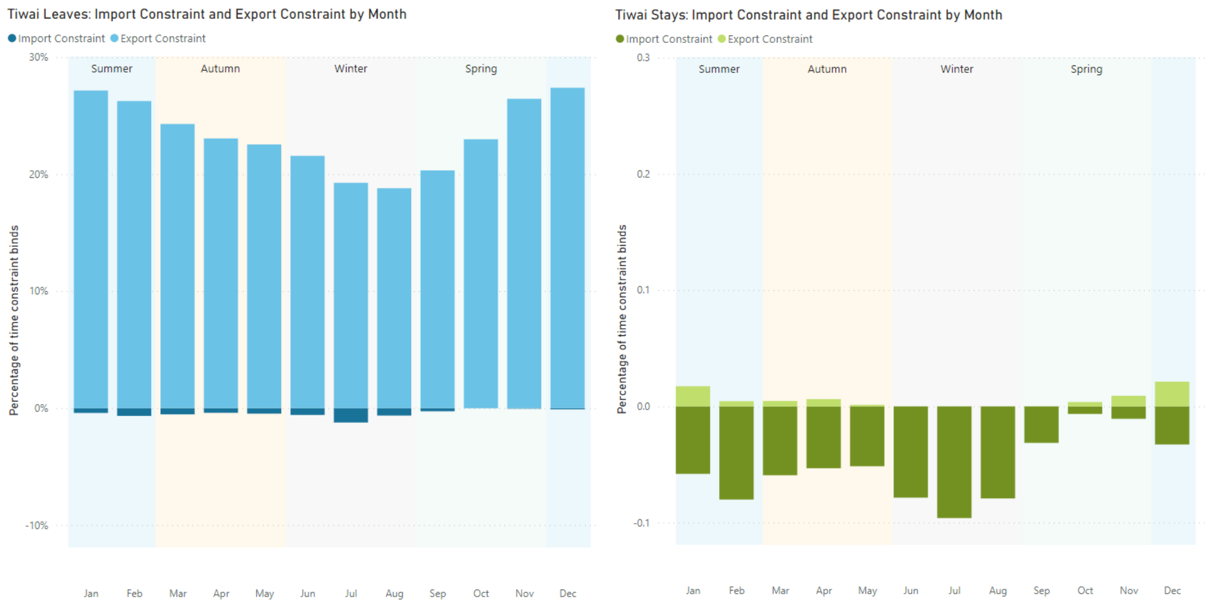


Figure 6 Graphs showing monthly binding constraints, for Tiwai leaves (left) and Tiwai stays (right) scenarios

48. The export constraint binds more often during late spring and summer as this is typically the highest inflow season for LSI generation when the majority of snow melt occurs.

49. The import constraint binds more often during winter when storage is low as inflows are lower on average and load is high. The graph in Figure 7 below shows average controlled storage for LSI hydro lakes across the seasons. Storage tends to be highest following the inflow season in spring and summer and then falls over autumn and winter, approaching its lowest level before the next inflow season starts.

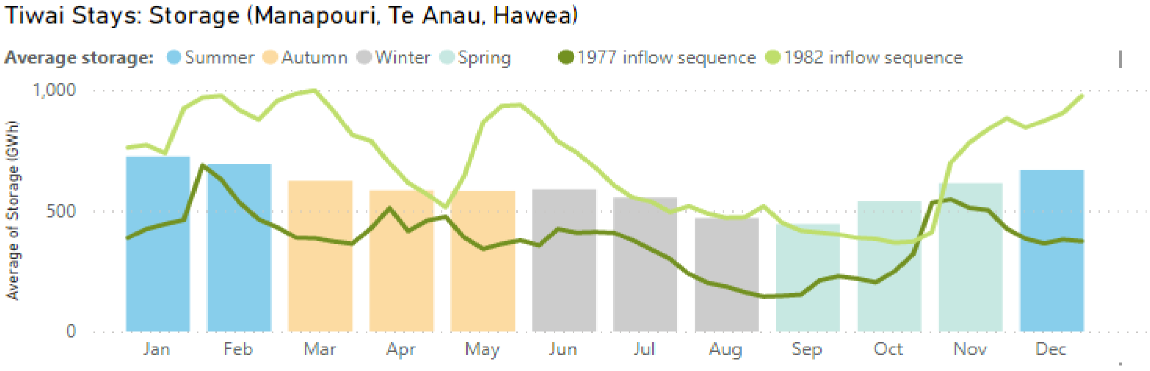


Figure 7 Average controlled storage for LSI hydro lakes by month and season

50. As examples, the 1977 inflow year[8] has low winter storage, and therefore also has the highest proportion of time with the import constraint binding over winter. The 1982 inflow year has high summer storage, and therefore has the highest proportion of time with the export constraint binding over summer.

51. Despite this seasonal pattern, constraints can bind at any time of year as inflows are volatile and because transmission line ratings change across seasons with ratings being lower in summer and higher in winter.

[8] Our model runs 86 simulations to represent variation in inflows. Each simulation uses inflows from a different historical year (between 1932 and 2017) for the first year of the study (2023) and then uses the subsequent historical year for the next year of the study, and so on until the end of the study period (2040). Storage levels for the example inflow years (1977 and 1982) are the averages over the different simulations of the storage levels throughout any study year that used the example inflow year (1977 or 1982). For example, the 1977 inflow year would have been used once for each of the 18 simulations whose inflow sequence started with an inflow year between 1960 and 1977 in the first study year.

3.6 Benefits change over time

52. The graphs in Figure 8 below show how often the constraint is expected to bind into the future to 2040.

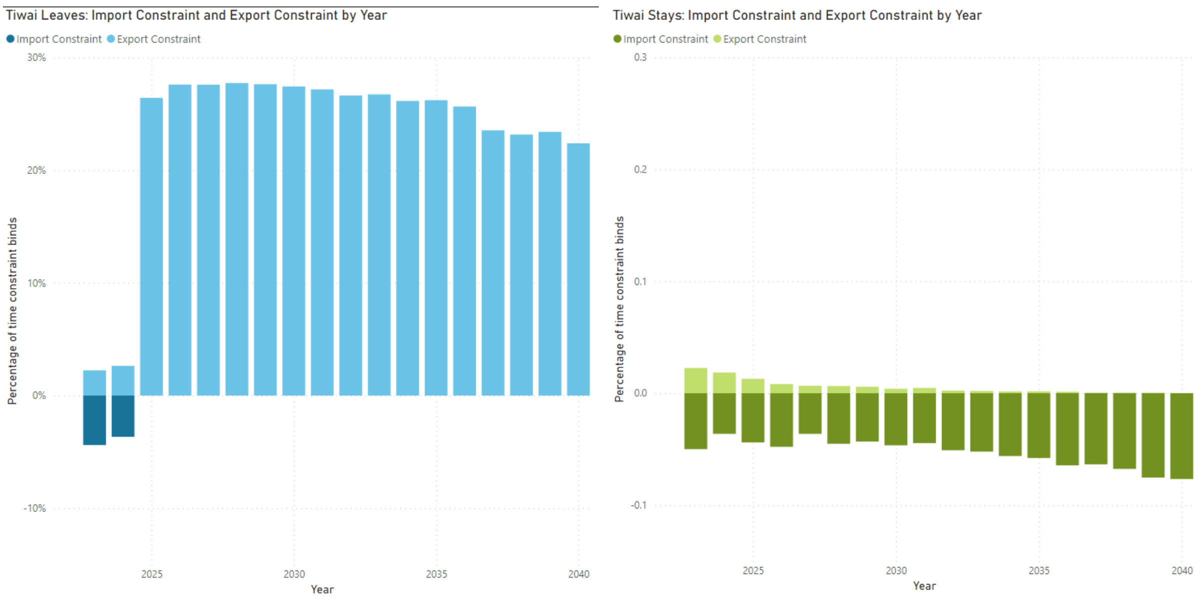


Figure 8 Forecast to 2040 of constraint bindings for scenarios Tiwai leaves (left) and Tiwai stays (right)

53. Benefits were assessed from the first year after CUWLP is expected to be fully commissioned (2023) up until 2040.
54. Note that expected benefits have been discounted at a rate of 7% per annum (see Section 4.8), meaning exposure to constraints binding in the earlier years is more important to prices.
55. The import constraint stops binding in the *Tiwai leaves* scenario after Tiwai leaves. The export constraint continues to bind into the future although this reduces somewhat in the latter years as more generation is built north of the constraint.
56. The import constraint binds more, and the import constraint less, over time in the *Tiwai stays* scenario as LSI load grows.

3.7 Indicative and final prices will be sensitive to input assumptions

57. These indicative prices may be sensitive to the simplifying assumptions made for the purposes of indicative pricing and to the assumptions and processes we applied that we intend to further develop, including:
    - Modelling only one EDGS scenario (with two variations), rather than all five EDGS scenarios
    - The amount, timing, and location of generation build based on the information specified in the EDGS
    - Our treatment of transmission losses.

58. Furthermore, final BBC prices will be sensitive to many assumptions even if we refine our processes and assumptions as best as possible, including:

    58.1 The assumed probability and timing of Tiwai leaving. The graphs in the previous sections don't fully demonstrate the importance of this assumption because they only show how often each constraint binds, not how much production or consumption is occurring at the time of the constraint. Because the import constraint in the *Tiwai stays* scenario binds more during winter, while the export constraint in the *Tiwai leaves* scenario binds more during summer, higher levels of load and generation are affected by the import constraint compared to the export constraint.

    58.2 Changes to the regional supply/demand balance. The generation and load balance assumed on each side of the constraint is likely to significantly influence the result, especially the balance in the Lower South Island. While we can limit this sensitivity by modelling several scenarios, modelled benefits will still be based on, and sensitive to, the resulting average of these scenarios.

    58.3 Fuel costs assumptions specified in the EDGS.

    58.4 The long run cost of self-supply assumption (see Section 4.8), although this is more likely to be relevant to other investments where significant benefits arise from reducing the amount of unsupplied load.

3.8 We consider these allocations are broadly proportional to EPNPB

59. In summary, we consider the allocations in this case study are broadly proportional to EPNPB[9] and consistent with clause iv, 8, and 23 of the Guidelines because:

    59.1 The beneficiaries in each scenario (Tiwai stays and Tiwai leaves) have been identified based on the marginal pricing principles that apply in the wholesale electricity market – e.g. loads downstream of the CUWLP constraint and generators upstream of the constraint benefit in the Tiwai leaves scenario.

    59.2 We have determined the results as an average of benefits in the future across two demand/supply scenarios and 86 hydrological scenarios (consistent with the term <u>expected</u> in EPNPB), which results in the beneficiaries in the Tiwai leaves scenario receiving the majority of the allocation. The Tiwai leaves scenario results in a higher allocation because the constraint in this scenario binds significantly more frequently than in the Tiwai stays scenario, which is consistent with the <u>net</u> term in EPNPB, which recognises a BBI can have positive and negative benefits for a customer depending on the scenario.

    59.3 The Tiwai stays scenario has some periods of scarcity prices in the LSI that contribute to high prices observed in the LSI in this scenario. However, the positive benefits to LSI load customers due to the BBI avoiding these high prices do not occur frequently enough to outweigh the negative benefits to them from the BBI in the Tiwai leaves scenario (i.e. because the BBI increases prices in the LSI in the Tiwai leaves scenario). In other words, these scarcity prices are not material

[9] Noting under the proposed TPM we need to consult on the input assumptions used for this BBI before determining final prices.

to EPNPB when considering positive net private benefits across the two scenarios.

59.4 Within a scenario, the allocations are based on the quantity of net load and generation that would receive higher/lower prices in the counterfactual, as well as any changes to the quantity of load and generation from the counterfactual (without the BBI) to the factual (with the BBI). The quantity of load or generation benefitting from a BBI is – for this BBI- a dominant factor given quantities can vary by >100 times across customers. The use of net load as an individual customer allocator recognises that disbenefits to embedded generation offsets positive benefits to load.

59.5 We have not accounted for the impact of downstream transmission constraints in the allocations (e.g. the HVDC), because, over time, these constraints would be expected to be at least partially relieved with either transmission or generation investments if they were material.[10] Furthermore, the price change over the HVDC is a less significant factor for EPNPB than the quantity of load and generation benefitting from the constraint being relieved. For example, the time-weighted average price at Benmore and Otahuhu between 2016-2020 was \$98/MWh and \$86/MWh, or 14%.[11] We also note because allocations are fixed over time, they cannot be reassessed in the future should downstream constraint be relieved (unless one of the adjustment provisions apply).

59.6 By applying clause 50A of the proposed TPM, we have assumed the change in price either side of the CUWLP constraint is equal in magnitude (and opposite in direction). For this BBI, because the generation benefitting from the BBI is hydro generation without significant operational costs, the change in price on the upstream side of the constraint in the Tiwai stays scenario can only be estimated using a complex stochastic hydrological model such SDDP which determines the water value (i.e. opportunity cost) of stored water based on an assumption of perfect competition. While this is appropriate for determining changes to electricity market costs under the investment test, for which market prices are typically not relevant, in reality, these generators have the ability to offer in the market at above their water value which would impact the actual private benefits realised. Therefore, the prices determine by SDDP are only a proxy for actual prices in the market. Similarly, for loads downstream of the constraint, the price is sensitive to generation investment assumptions (as demonstrated in Chapter 7 (BBC allocation). Given there is not a clear and obvious change in price to assume either side of a constraint, and in the absence of the ability to model a very large number of scenarios due to computational resources, we consider the simplifying assumption of an equal price change to be broadly proportional to EPNPB.

10 Noting the North Island is a sufficiently large region that grid-scale generation is a credible alternative to mitigate the constraint, which may not be the case for smaller regions.

11 This price difference includes the effect of losses which may not be reflected in the private benefits of CUWLP We note that benefits due to CUWLP are determined based on comparison between a future with CUWLP and a future without. The loss effect on prices may be the same in both futures, or it may be greater in the counterfactual for downstream nodes due to the same percentage loss effect being applied to a higher price, or it may be lower as increased transmission flows in the factual lead to higher losses.

59.7 The allocations are strongly influenced by the assumptions that would determine the benefits if applying the investment test – in particular, if Tiwai leaves or stays, the weighting of these two scenarios, and the hydrological inflow scenarios. This is consistent with clause 23 of the Guidelines, which requires alignment with the treatment of benefits assessed through the investment test (if we consider this will result in allocations proportional to EPNPB).

59.8 We do not expect CUWLP to have material reliability, ancillary service, or other benefits, therefore the allocations have not applied clauses 51, 52, or 53 of the proposed TPM.

4 How we applied the TPM for this case study

60. In this section, all terms in bold are the terms as defined in the proposed TPM and references to clauses are to clauses of the proposed TPM (unless otherwise stated).

61. This section describes how we have determined indicative **benefit-based charges** (**BBC**s) for this case study by applying the proposed TPM. A **BBC** is a **customer's** charge for a benefit-based investment (**BBI**). CUWLP is a **BBI**.

62. **BBCs** are calculated for each **pricing year** by multiplying each **beneficiary's BBI customer allocation** by the **BBI's covered cost** (clause 36(2)).

62.1 Section 4.1 describes how we determined the **covered cost** of CUWLP (clauses 40 and 41).

62.2 Section 4.2 describes how we classified CUWLP and therefore determined that the **price-quantity method** would be used to calculate **customers' net-private benefits** from CUWLP (**individual NPBs**) (clause 43(2)).

62.3 Section 4.3 comments on the consultation requirements for CUWLP (clause 17).

62.4 Section 4.4 provides an overview of the **price-quantity method** (clause 44).

62.5 Section 4.5 describes how CUWLP is not a **tested investment**, and therefore the assumptions we use do not need to be aligned with the treatment of benefits used in the investment test (clause 43(3)).

62.6 Section 4.6 describes how we determined the **factual**, **counterfactual**, and **investment grids** for CUWLP (clauses 45, 50(2)).

62.7 Section 4.7 describes how we determined the **market scenarios** for CUWLP (clause 46)

62.8 Section 4.8 describes how we determined some other input assumptions relevant to calculating the **customers' individual NPBs** for CUWLP, some of which may be carried into the **assumptions book** for use with other **BBIs**.

62.9 Section 4.9 describes how we determined the changes in prices and quantities between the **factual** and **counterfactual** using our **wholesale market model** (clause 50(3)).

62.10 Section 4.10 describes how we determined the **modelled regions** for CUWLP (clause 50A(2)).

62.11 Section 4.11 describes how we calculated the **regional NPBs** for CUWLP (clause 50A(4) to 50A(8)).

62.12 Section 4.12 describes how we determined the **regional customer groups** for CUWLP (clauses 50A(2) and 50A(3)).

62.13 Section 4.13 describes how we determined the present values of the **regional NPBs** for the **regional customer groups** (**PVRNPBs**) (clause 49).

62.14 Section 4.14 describes how we determined each **customer's intra-regional allocator** (clause 63).

62.15 Section 4.15 describes how we determined **individual NPBs** as a proportion of the **PVRNPBs** based on the **intra-regional allocators**, then determined **BBI customer allocations** based on **individual NPBs**, then calculated **BBCs** for an example **pricing year**. (clauses 48, 43 and 36).

4.1 Covered cost and attributed opex (clauses 40 and 41)

63. We have estimated the **covered cost** and **attributed opex** according to clauses 40 and 41 of the proposed TPM based on the following assumptions. A graph of estimated covered cost, figure 9 below, shows the cost profile. The actual covered cost would be based on actual capital costs, depreciation, and WACC.

- A forecast capital cost of $100m
- Commissioning in June 2022
- **Depreciation** of $2.7m p.a. based on an estimated average accounting life for the assets that make up the project of approx. 38 years and straight-line depreciation
- Constant vanilla WACC of 4.57% p.a. based on Transpower RCP3 WACC
- Attributable opex of $2.7m p.a., using a constant forecast **attributed opex ratio** of 1.01 based on the forecast ratio for RCP3.

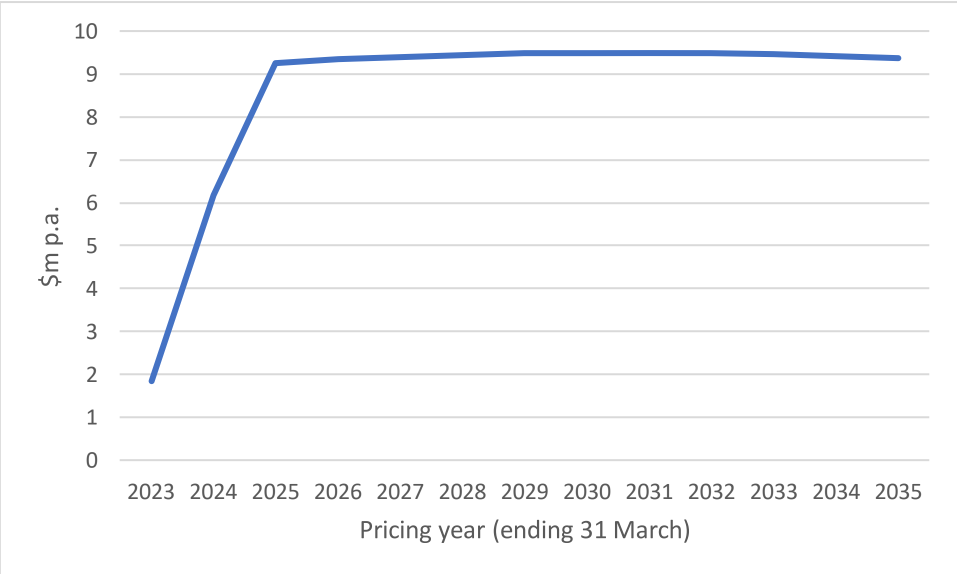


Figure 9 Covered cost profile $m per year.

4.2 Classifying the BBI and determining the standard method to be used (clause 43(2))

64. This section describes the TPM clauses used to classify the **BBI** and determine which standard method is used.

65. Under the proposed TPM, CUWLP is considered as a **high-value**, **post 2019 BBI**[12] as its forecast cost is expected to be approx. $100m, greater than the $20m base capex threshold defined in the **Transpower Capex IM**.

66. The proposed TPM includes four types of **BBI** (**market**, **reliability**, **ancillary service**, and **resiliency**). We consider CUWLP to be a **market BBI**, because the investment is expected to have a material impact on prices or volumes in the wholesale market.

67. **Market BBIs** can also be considered **reliability**, and **ancillary service BBIs,** and **other regional NPB** can also be used to determine allocations:
    - We do not expect the **BBI** to result in a material decrease in the cost of ancillary services, therefore we have not assessed this as an **ancillary service BBI**.
    - CUWLP does not add new circuits or change the configuration of the electricity network, therefore we do not expect this to have a material effect on the reliability of the power system, so we have not assessed it as a **reliability BBI**. As explained in Chapter 7 (BBC Allocation), avoided unserved energy due to pre-event demand management is assessed through the **market BBI** framework.
    - We are not aware of any other private benefits that meet the criteria of clause 53(2) of the proposed TPM, therefore we have not included in **other regional NPB** in the allocations.

68. As a **high-value, post-2019, market BBI,** a customer's **net-private benefit (NPB)** will be calculated in accordance with the **price-quantity method** (43(2)). To avoid doubt, under the proposed TPM we cannot add the costs of the CULWP project to the LSI renewables project under Schedule 1, nor can we apply the allocation against the LSI renewables in Schedule 1, to CUWLP (see the definition of **Appendix A BBI** in the proposed TPM).

4.3 Consultation (clause 17)

69. Clause 17 specifies the consultation requirements for a **BBI**.

70. Because this component will be commissioned after June-2019 but was committed before the proposed TPM will come into effect, we have not conducted consultation on the covered cost or benefit-based allocations for this component. We will do this after the new TPM has been approved by the Authority.

---

[12] **high-value** means, for a BBI, that the depreciated value of the BBI at the relevant time is more than $20m; **post-2019 BBI** means an interconnection investment commissioned after 23 July 2019.

4.4 Overview of price-quantity method (clause 44)

71. As determined in Section 4.2, we will use the **price-quantity method** to assess benefits for CUWLP. As determined in Section 4.2, CUWLP is a **market BBI,** is not an **ancillary service BBI,** is not a **reliability BBI,** and is not an **other BBI**.
72. According to clause 44(2), under a price-quantity method we must calculate a **market regional NPB** using clauses 50 to 50B for a **market BBI** for **regional customer groups**, and **individual NPB** are calculated for each **customer** in a **regional customer group** with positive **regional NPB**.

4.5 Alignment with Investment Test (clause 43(3))

73. CUWLP is not a **tested investment** because it was originally approved by the Electricity Commission, not the Commerce Commission under the current investment approval regime.
74. Therefore, clause 43(3) does not apply (which would require us to use assumptions that are as consistent as reasonably practicable with the assumptions used in the original **Investment Test**). This is relevant because the scenarios used for the 2009 proposal would likely not be proportional to EPNPB at the time of setting the charge if we were to apply the test today, over a decade later.
75. When producing final allocations for CUWLP following the Authority's finalization and approval of the proposed TPM, we intend to use similar assumptions to what we would use if we were to re-apply the Investment Test. This has largely been our approach for this case study, although some simplifications have been made.

4.6 Factual, counterfactual, and investment grids (clauses 45, 50(2))

76. This section covers how we determined the **factual**, **counterfactual**, and **investment grids** for this case study.
77. To calculate the **regional NPB** for a **market BBI**, we must determine the **investment grids** for the **factual** and **counterfactual** (clause 50(2).
78. The **counterfactual** refers to the grid state without the investment, and the **factual** refers to the grid state with the investment.
79. An investment grid is a simplified model of the grid that models all existing **market nodes**, the constraints on the HVDC link and the **market BBI's modelled constraints**.

Factual and counterfactual (clause 45)

80. The factual and counterfactual can differ over the **standard method calculation period**.
81. We determined the **counterfactual** for CUWLP to be the current state of the grid.
82. We determined the **factua**l for CUWLP to be the grid after all assets have been fully commissioned.

83. For other investments, the **factual** may change over time as different stages of the investment are commissioned. Charges would be applied after the first assets are **commissioned** (clause 37(1)).

84. CUWLP is expected to be fully **commissioned** soon after the start of the first financial year the TPM may apply to (2021/22 for pricing in 2023). Benefits have been calculated assuming CUWLP is fully **commissioned** in the **factual** so that calculated benefits align with the period over which **customers** will be charged.

85. For simplicity we have calculated benefits from the start of the 2023 calendar year. For the purposes of this case study the **standard method calculation period** over which benefits have been calculated is 2023 to 2040 (inclusive). When applying the TPM in practice we will calculate benefits over the 20 year period following CUWLP being fully **commissioned**, as the TPM requires the **standard method calculation period** to be the lesser of 20 years and the difference between the end of the useful life of the **BBI** and the **BBI**'s **commissioning date**. We do not expect the extra two years to materially change the result of this case study.

86. For other **BBIs**, the **counterfactual** may change over time if a grid asset that is part of the **BBI** is expected to be replaced within the **standard method calculation period**. In that case the **counterfactual** would include the **decommissioning** of the relevant assets at the end of their useful life.

Investment grids (clause 50(2))

87. In accordance with clause 50(2), Transpower must determine the **market BBI's investment grids**.

88. The **investment grids** are simplified models of the grid including market nodes, branches, and the collection of constraints applied to the **factual** and **counterfactual**; the constraints comprise limits on the **HVDC link** and any **modelled constraints** associated with the investment.

89. The **modelled constraints** we will typically model are often referred to as n-1 transmission constraints. If a circuit trips, the power previously flowing through it will now flow through parallel paths. n-1 transmission constraints limit flow on two parallel circuits to protect one circuit (the protected circuit) from overload should the other circuit (the contingent circuit) trip. We define such constraints as a pair of circuits including a protected circuit and a contingent circuit.

90. For this case study, the **modelled constraints** are n-1 transmission constraints (see below) whose protected circuits were those being upgraded as part of CUWLP. The circuits being upgraded as part of CUWLP include the two circuits between Cromwell and Twizel (CML_TWZ1 and CML_TWZ2), the circuit between Naseby and Roxburgh (NSY_ROX), and the circuit between Livingstone and Naseby (LIV_NSY).

91. **Modelled constraints** should bind much more often in the **counterfactual** where the circuits have not been upgraded. Constraints are modelled in the **factual** as well because constraints may still bind in certain situations in the **factual** or in later years within the **standard method calculation period** when demand and supply are significantly different, depending on the **scenario**.

92. There were two predominant constraints for this case study, one which bound in times of export out of the LSI and one which bound in times of import. In this document we refer to these as 'export constraints' and 'import constraints'. They were

- For export, protecting the NSY_ROX circuit for the contingency of a CYD_CML circuit.
- For import, protecting the LIV_NSY circuit for the contingency of a CML_TWZ circuit.

93. The constraint limits for the **modelled constraints** change seasonally, matching how n-1 transmission constraints are modelled in the market system that is used to determine dispatch and spot prices in the wholesale electricity market. The seasonal change is due to the changing air temperature, with lower limits in summer and higher in winter. When a circuit heats due to increasing power flow or air temperature, it sags, bringing it closer to the ground. Circuit ratings are based on an allowable level of sag that ensures a safe level of ground clearance**.**

94. More information on the **modelled constraint** inputs is available on request.

4.7 Market scenarios (clause 46)

95. This section describes the **market scenarios** we used in this case study and how we determined them.

96. To calculate the **regional NPB** for a **market BBI**, Transpower must use a **wholesale market model** to model the changes in prices and quantities between the **factual** and **counterfactual** under its **market scenarios** and based on its **investment grids** (clause 50(3)).

97. Clause 46 of the proposed TPM specifies the requirements for the **scenarios** used in the **price-quantity method**, in particular, that we:

- assess variations in load growth, generation development, and hydrology (clause 46(1)), and
- must apply the same **scenarios** in a **BBI's factual** and **counterfactual**, unless we expect the existence of the **BBI** to materially influence generating plant investment decisions, in which case we may use different generation development **scenarios** (clause 46(2)).

98. For this case study we modelled two sets of **scenarios** to represent variations in load growth and generation expansion, which we refer to as *Tiwai stays* and *Tiwai leaves* throughout this document. We modelled 86 hydrological inflow sequences, for both *Tiwai stays* and *Tiwai leaves* scenarios, to represent variations in hydrology. In this appendix we refer to *Tiwai stays* and *Tiwai leaves* as 'scenarios', while the **scenarios** representing the different inflow sequences we refer to as 'inflow sequences'.

Variations in hydrology

99. We modelled 86 hydrological inflow sequences.

100. The 86 hydrological inflow sequences were based on historical weekly inflows between 1932 and 2017 inclusive. The **standard method calculation period** for CUWLP was

from 2023 to 2040, inclusive. Each simulation started in 2023 using a different historical inflow year, with 2024 being the subsequent historical year, and so on. After the 2017 historical year was used, the next year would be 1932. The inflow sequences are sourced from the Hydrological Modelling Dataset, published on the Electricity Market Information website[13]. All results in this document, for each of the *Tiwai stays* and *Tiwai leaves* scenarios, are the mean of these 86 sequences (unless otherwise stated).

101. We used historical inflow sequences because they capture realistic variability and temporal correlation between inflows (e.g. the likelihood of it raining this week if it rained last week).

We expect the **assumptions book** (see Section 4.8) will specify the above assumptions or similar, rather than them being revisited on an investment by investment basis.

Variations in load growth and generation development

102. When applying the TPM in practice, we would expect to use the same or similar **scenarios** as used when applying the Investment Test, which – for a major capex project – requires us to use MBIE's EDGS (five in the latest EDGS published in 2019), or reasonable variations on these **scenarios**. As allowed for under the Investment Test, we sometimes vary the EDGS when they are no longer up to date, for example, due to the increased likelihood of Tiwai being decommissioned. For this case study we have used the EDGS variations as described in our December 2020 EDGS variation consultation[14], except where otherwise stated here. The **scenarios** are summarized below, and more detailed information is available on request.

103. We have used two **scenarios - ***Tiwai leaves* and *Tiwai stays* **-** in this case study based on the Disruptive **scenario** from the EDGS. . These scenarios comply with 46(1) by:

- varying electricity demand as shown in Figure 10 below. One **scenario** assumes Tiwai remains for the full analysis period and one assumes Tiwai leaves at the end of 2024, otherwise the two **scenarios** have the same demand assumptions. We chose to vary Tiwai's demand as this is the key demand uncertainty that affects the **beneficiaries** of this **BBI**.

---

13 Electricity Authority - EMI (market statistics and tools) (ea.govt.nz)
14 EDGS 2019 Variations Consultation for future scenarios

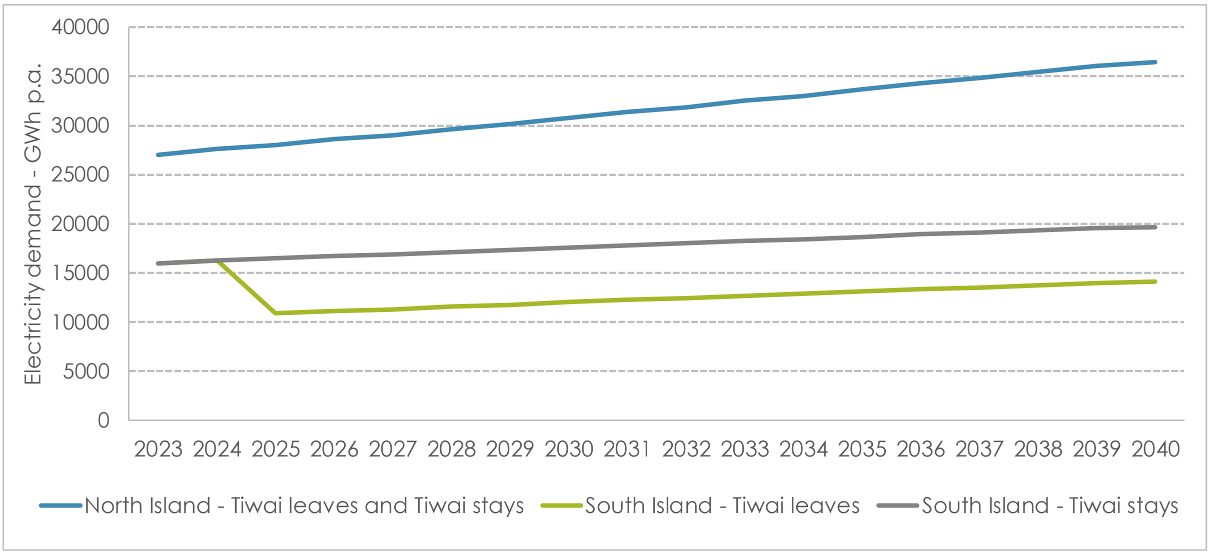
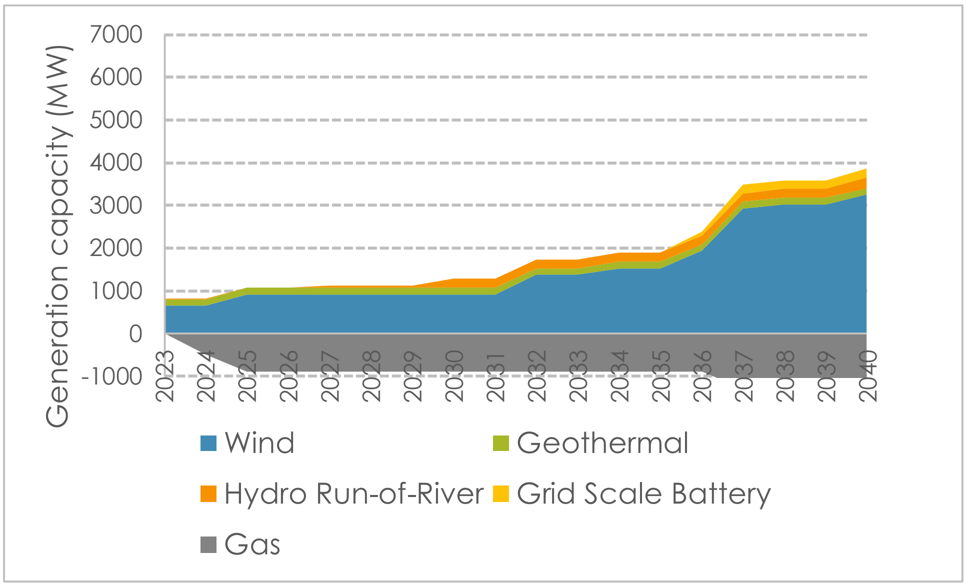


Figure 10 Forecast electricity demand in the North and South Islands, for Tiwai leaves and Tiwai stays scenarios

- using different generation development assumptions in the *Tiwai stays* and *Tiwai leaves* **scenarios**, as shown in Figure 11 to Figure 13.[15] We have complied with 46(2) by using different generation development scenarios in the **factual** and **counterfactual** for the *Tiwai leaves* **scenario**. This is because our generation development **scenarios** have been developed without AC transmission constraints and, without CUWLP, in our early test runs there was a significant shortfall of electricity generation north of the Lower South Island towards the second half of the analysis period due to the generation lost to spill in this **scenario**. This shortfall was resulting in high market prices causally unrelated to the **BBI** itself, so in the final **scenarios** used here we commissioned additional generation in the North Island in the **counterfactual**.



[15] Note, the negative values for Gas stations represented decommissioned plant.

Figure 11: Tiwai leaves, with CUWLP (factual) generation development scenario

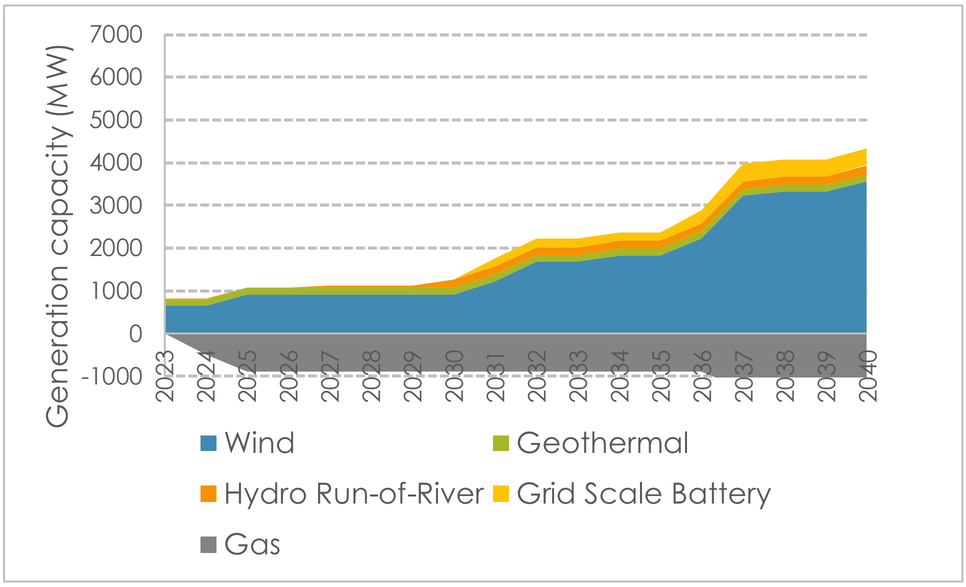


Figure 12: Tiwai leaves, without CUWLP (counterfactual) generation development scenario

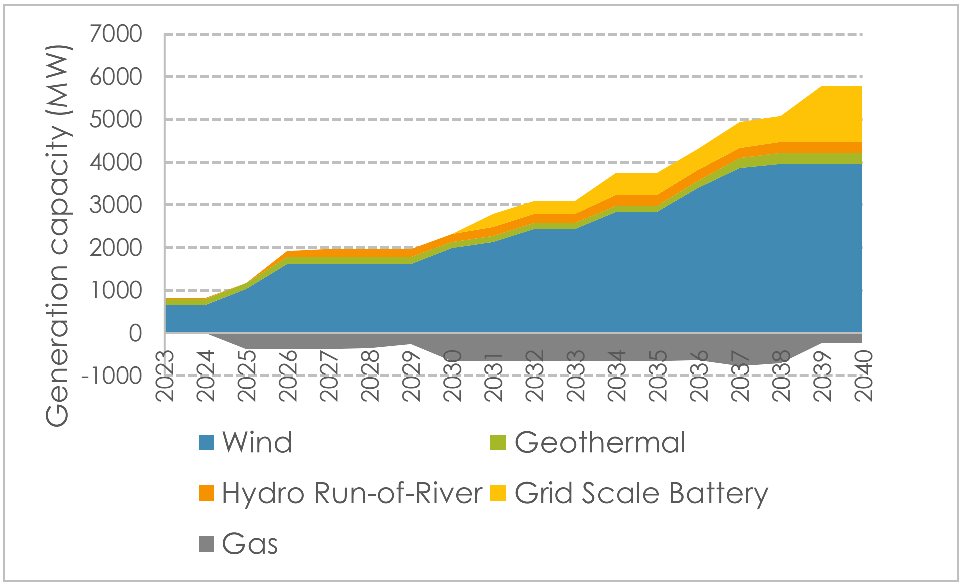


Figure 13: Tiwai stays generation development scenario (used for both factual and counterfactual)

104. We note these generation development **scenarios** differ from the usual methodology we use to produce generation development **scenarios.** Unlike the scenarios in our EDGS variation consultation, we have not attempted to prompt the scenarios towards a specific technology in order to achieve variation. Rather, these **scenarios** are the least cost generation stations as determined by an optimisation model. We used this approach for this case study in order to better achieve market prices that are reflective of the long-run cost of generating electricity; however, a combination of the two approaches may be required in the future, and we would expect to assess more variation in generation development than represented by the **scenarios** used in this case study.

105. Based on our experience with this case study, we have found the generation development **scenarios** are a key assumption that affects the proportion of private benefits falling to generation vs. load. Ultimately, we may need to use a different approach than that used in the Investment Test because of the importance of these assumptions in determining allocations between generation and load, particularly if we are using clause 50B of the proposed TPM. However, we consider the proposed TPM gives us the flexibility to depart from the Investment Test where we think this is required to better reflect private benefits (rather than efficiency benefits).

106. In determining allocations, we have chosen a 50-50% weighting between these scenarios as we have no reason to believe a different weighting is more justifiable

4.8 Other input assumptions

107. This section covers the information we have used for this case study that may ordinarily be captured in the assumptions book. The assumptions book doesn't just include assumptions used for **market BBIs**, it also includes assumptions used in applying the TPM more generally. This section includes only those assumptions we have used in applying this **market BBI**.

108. The assumptions required for **market BBIs** include the choice of **wholesale market model** and the inputs used in that model.

109. Clause 39 requires we publish an **assumptions book**, which is intended to contain the assumptions and analytical processes used to produce **BBCs** that do not change on an investment-by-investment basis. We intend to develop and consult on this **assumptions book** after the Authority finalises and approves the proposed TPM.

110. We describe some of the key assumptions used in this case study below, with more detailed information available on request.

Discount rate

111. As required by clause 49 of the proposed TPM, **regional NPB** is discounted using the **standard method discount rate**. As explained in Section 4.5, CUWLP is not a **tested investment**. Therefore, we have used the 7% pre-tax real rate specified in clause D6(3)(a) of the **Capex IM**.

Choice of wholesale market model

112. According to clause 50(3), we must use a **wholesale market model** in determining net private benefits.

113. We have used SDDP as our **wholesale market model** for this case study because:
   - it is a least cost dispatch model, as required under the definition of **wholesale market model**
   - we currently use it when undertaking the Investment Test where market benefits are being analysed.

- it can adjust the scheduling of hydro generation depending on inflows and reservoir storage levels, thereby accounting for different hydrological scenarios as required by clause 46(1).

Inputs to wholesale market model

114. The **wholesale market model** requires some inputs that may change on an investment by investment basis, as well as some that we expect will not.
115. The inputs that may change on an investment by investment basis are those that have been covered in previous sections, that is
    - The investment grid representing the **factual** and **counterfactual**
    - Market scenarios
116. Despite the above inputs changing on an investment by investment basis, we expect some information about them to be captured in the **assumptions book**. For the two **investment grids** used in the **factual** and **counterfactual**, we would specify the basis of the grid model and our process for determining **modelled constraints**. For the **market scenarios**, we expect to specify that we will base our **scenarios** on historical inflow sequences and on the information contained in EDGS.
117. Inputs to the **wholesale market model** that we expect not to change on an investment by investment basis (included in the **assumptions book**), include:
    - Operating costs for the various generation types, based on the costs specified in the EDGS (or variations)
    - Technical parameters specifying hydrological networks (e.g. storage capacity, spill paths, minimum and maximum flow rates etc.)
    - Technical parameters defining how a given generator operates (e.g. minimum and maximum operating capacity)
    - A cost of unsupplied load (long run cost of self-supply)
    - The way we treat transmission losses
118. A least cost dispatch model must have operating cost information for generators in order to choose the least cost generators at any point in time.
119. The technical and cost parameters of thermal, geothermal, wind and solar plants are taken from the 2020 update to the New Zealand Generation Stack[16,] with the exception of carbon costs, which are sourced from the Climate Change Commission (CCC) as these had been updated more recently. Important cost parameters include,

    119.1 Gas fuel prices are a flat $6.2/GJ and coal prices are a flat $7.79/GJ.

    119.2 Carbon costs consistent with CCC's advice for a cost containment reserve price of $70/t CO_{2e} at the first possible opportunity, increasing by 10% p.a.[17].
120. For hydro-generators, SDDP includes an initial stage, called the policy, to calculate water values. Water values represent the opportunity cost of using water now, instead

16 New Zealand generation stack updates | Ministry of Business, Innovation & Employment (mbie.govt.nz)

17 See recommendation 11 in the CCC's advice to the government: Ināia tonu nei: a low emissions future for Aotearoa » Climate Change Commission (climatecommission.govt.nz)

of storing it for later use. Water values are calculated for a given point in time as a function of reservoir storage levels. They can be thought of as offers by hydro generators in the market dispatch model.

121. We have modelled various aspects of hydrological networks, including the storage capacities of hydro reservoirs, the dependence between river flows on one part of the river and generation upstream, and resource management constraints.

122. We have also modelled other constraints on how generators operate, including must-run constraints for geothermal, and commitment constraints for some thermal generators. Thermal commitment constraints enforce that these generators come on for a full week at a time.

123. A cost of self-supply of $1000/MWh for 10% of demand, and $2000/MWh for the remaining 90% of all demand (referred to as P_{max} in clause 50(4)). These values have been previously derived to achieve realistic hydro storage offer behaviour, as they are a key parameter used by the model to determine how much stored water to conserve in order to avoid running out of generation in a dry year.

124. We haven't modelled AC losses explicitly, but we have for losses across the HVDC. We have increased load to account for the effect of AC losses on the quantity of generation required. This is typically what we do for the Investment Test, as functionality in SDDP to model AC losses explicitly at the same time as modelling transmission constraints has only recently been introduced, as a beta version. We have also found that modelling losses can increase the solve time tenfold. In the Investment Test we assess changes in electricity market costs (i.e. efficiency benefits), which will arise predominantly from alleviating transmission constraints, not by reducing losses.[18] If the efficiency benefit of losses is significant it has typically been modelled in post-processing, rather than within SDDP. We are still developing our treatment of losses under the **BBC**, but consider the proposed TPM gives us the flexibility to develop and change our approach over time.

4.9 Model changes in prices and quantities using wholesale market model (clause 50(3))

125. This section covers how we used our **wholesale market model**.

126. Clause 50(3) requires Transpower to use a **wholesale market model** to model changes in prices and quantities between the **factual** and **counterfactual** for each **market scenario** and based on its **investment grids.** It also requires that the modelling cover each year of the **BBI's standard method calculation period.**

127. After selecting our model and determining all our inputs we ran the model between 2023 and 2040 (inclusive) for each of 86 inflow sequences, for both the Tiwai Leaves and Tiwai Stays scenarios.

128. Our dispatch model is run for 21 different load levels within each week, representing the variation in forecast load within that week.

[18] Although losses are often an important benefit when assessing between transmission options (e.g. different conductor types).

129. To assess net private benefits, we produced the following outputs for each run, for each load block of each week within the **standard method calculation period**:

- Dispatch for each generating station
- Load supplied at each node
- Prices at each node/station
- Producer and consumer surpluses per generating station or load node
- Th periods during which each constraint binds.

130. After producing these outputs, we also produced the following discounted annual values[19] for each year (study year) within the **standard method calculation period:**

- Total dispatch for each generating station
- Total load supplied at each node
- Time weighted average prices across the year
- Total producer and consumer surpluses per generating station or load node
- All of the above were also produced during times of export constraints binding, at times of import constraints binding, and at times of no constraints binding.

131. These discounted values were used for determining **regional customer groups** and the **present value of regional NPBs (PVRNPBs)**, as discussed in the following sections.

4.10 Determining modelled regions (50A(2))

132. The next step in the process is to determine if 50A will result in **customer BBI allocations** that are broadly proportionate to **NPB**. To make this this determination in practice we need to follow 50A and assess the suitability of the resulting allocations.

133. The first step of 50A, as described in this section, is to determine **regional customer groups** by first determining **modelled regions** under clause 50A(2). We have determined regional supply and demand sub-groups within these regions in section 4.12.

134. According to clause 50A(1), clause 50A applies if its application results in **customer BBI allocations** that are broadly proportionate to **NPB**. Application of clause 50A requires at most two **modelled regions** (each for regional supply groups and regional demand groups). Therefore, a key first step in assessing the applicability of clause 50A is to assess the suitability of assuming at most **two modelled regions**. This section describes how we determined two **modelled regions** under clause 50A(2) and the suitability of this assumption.

135. More generally, the determination of whether 50A will result in **customer BBI allocations** that are broadly proportionate to **NPB** involves several other factors, which we describe in subsequent sections (and summarised in section 3.8).

[19] Values were aggregated to the annual level prior to discounting. No intra-year discounting was applied.

136. In determining **modelled regions**, 50A(2) requires the use of the outputs of the modelling under clause 50. Clause 50A defines **modelled regions** as a set of **GXPs** or **GIPs** (**market nodes**) in which modelled price changes are in the same direction.

137. For electricity market benefits under the proposed TPM, **modelled regions** depend on the locational price separation caused by transmission constraints. Because we are not modelling the price effect of AC losses, prices will be exactly the same across nodes within an island except when a constraint binds. When alleviating a **modelled constraint**, we would expect the locations whose prices had separated when the constraint was binding to experience price changes.

138. We assessed **modelled regions** by looking at the time weighted average price (TWAP) at different nodes during times when the **modelled constraints** were binding in the **counterfactual**. The price impact of the HVDC constraint binding is likely to be the greatest at times of the **modelled constraints** binding, therefore at these times it would be most justifiable to include the North Island (NI) as its own **modelled region**. We have not assessed other times when the HVDC constraint was binding, because the analysis below doesn't justify NI as being its own region.

139. For the export constraints[20], prices are lower in the LSI - upstream of the constrained circuits (Roxburgh to Naseby and Cromwell to Twizel), and higher in the rest of the country. There is a mild spring washer, or loop flow effect, causing differences in prices between downstream locations, with prices highest at Naseby. Prices at Naseby represent the cost of supplying the next MW of load. But because the next MW needs to come from downstream generation, in order to get to Naseby it will also flow down parallel paths which loop back around through Twizel to Roxburgh to Naseby. But because the Roxburgh to Naseby circuit is constrained, some LSI generation will need to be backed off in order to let this extra flow through. This means more than 1 MW of relatively expensive downstream generation is required to meet the 1 MW of load, which costs more, hence the higher price. Similar effects occur for other downstream **market nodes**, but to a lesser extent.

140. We do not consider separate regions are justified based on the loop flow/spring washer effect because:

- the modelled spring washer effect is mild for these **market nodes**
- spring washer effects are highly sensitive to inputs
- the effect for each node depends on the location of the next MW in the stack, which is sensitive to assumptions, and
- the effect for each node depends on the precise location of future generation build, which is particularly uncertain.

141. For the import constraint, prices are lower upstream of the constrained circuits (Livingstone to Naseby and Twizel to Cromwell) and higher downstream, with the exception of Ohau and Twizel. There is a loop effect extending from Livingstone (where prices are lowest) around through Waitaki and Islington through to Twizel, to

[20] In this and subsequent sections where we assess times of modelled constraints binding, these include times when constraints other than the predominant constraints bind; however, these other constraints bind so infrequently that for the purposes of these discussions it is reasonable to consider only the effect of the predominant constraints specified in Section 3.6.

Cromwell, to Clyde, to Roxburgh (where prices are highest). The loop flow effect is being driven by the effect of parallel flows going through the protected circuit (Livingstone to Naseby), as this is the circuit with the highest weighting in the constraint. This means, if the loop flow effect is strong enough, prices can increase rather than decrease at nodes upstream of the contingent circuit (Twizel to Cromwell). Whether or not this occurs depends on the strength of the loop flow effect.

142. The strength of the loop flow effect is highly sensitive to assumptions, as discussed above. We note that the magnitude of difference in modelled price change between nearby Timaru (which has a positive price change) and Twizel (which has a negative price change) is only approximately $2/MWh, suggesting a small change in assumptions could cause the price change to flip directions.

143. For the purposes of this case study we are assuming any **market nodes** downstream of either the protected or contingent circuit will have a decreased price when the constraint is alleviated in the factual. We note that the price effects may become clearer when we apply the TPM in practice, as we intend to model further scenarios and will have the opportunity to test our conclusions further.

144. Due to Naseby's unique position to the import and export constraints, Naseby is identified as benefitting for both modelled constraints. In other words, Naseby's prices rise in the counterfactual in both cases. This is because on the Roxburgh-Naseby-Livingstone line it is the Roxburgh to Naseby section that is constrained for the export constraint and the Livingstone to Naseby section for the import constraint. We have grouped Naseby with the downstream loads in the Tiwai leaves scenario, because this is the dominant constraint that results in the majority of the final allocation for this case study. Therefore, grouping Naseby in this region results in a **BBI customer allocation** that best reflects its EPNPB.

145. We have not determined the North Island (NI) as a separate region. The price changes between the factual and counterfactual for NI falls in the middle of the range of price changes affected by the loop flow effect, because Benmore, and by extension NI, is in the middle of this loop. Also, the price changes are similar on average for NI compared to Benmore. During times of the export constraint binding in the counterfactual for *Tiwai leaves*, the modelled price change for NI, Benmore, and Invercargill are -$16, -$19, and -$26 respectively between the years 2023 to 2030[21].

146. The **modelled regions** for CUWLP are therefore:

- LSI, including Cromwell, Frankton, Clutha, Roxburgh, and all nodes south of Roxburgh
- The rest of the grid.

[21] We have looked at the period 2023 to 2030 because allocations are based on discounted benefits, therefore the earlier years have a greater weighting. Also, as we are still developing our process for developing the generation build schedule in the context of transmission pricing, for this case study we may have overbuilt generation in the counterfactual for *Tiwai leaves*.

4.11 Calculation of Market Regional NPB (50A)

147. This section describes how we have calculated **market regional NPB** using clause 50A, and why we have chosen to use clause 50A rather than clause 50B.
148. Clause 50A provides a method for calculating **market regional NPB** that applies if Transpower determines its application will result in **BBI customer allocations** that are broadly proportionate to expected positive **NPBs**. Clause 50B applies if Transpower determines that the application of 50A will not result in **BBI customer allocations** that are broadly proportionate to expected positive **NPBs.**
149. Clause 50A uses simplifying assumptions in the price and costs dimensions. Clause 50B uses the price and costs information directly from the wholesale market model.[22]
150. In this section we first describe how we have applied clause 50A. We then describe how we have determined this application will result in **BBI customer allocations** that are broadly in proportionate to net private benefits.

The method, step by step

151. We have identified periods of primary benefit, as required by clause 50A(4)(b), to be:
    - periods when a **modelled constraint** binds in the counterfactual, for benefits relating to price changes
    - the entire **standard method calculation period**, for benefits relating to quantity changes.
152. Based on these periods, clause 50A implies that the magnitude, though not direction, of price changes due to alleviating **modelled constraints** is the same for the LSI as it is for the rest of the country, the same between import and export constraints, and the same across time. It is also implied that the benefits per unit of quantity are the same for quantities exposed to the **modelled constraint** binding in the counterfactual as they are for additional quantities released by alleviating the **modelled constraint**.
153. We note that we applied discounted values in the application of 50A(4), as allowed under clause 49(2). This enabled us to determine **regional supply groups** and **regional demand groups** (see following section) by considering how the grouping would affect their allocations, as allocations are based on **individual NPBs**, which in turn are based on **PVRNPBs**.
154. The steps below show how we applied clause 50A(4).
155. Step 1: For each scenario and inflow sequence,

    1. We calculated relative benefits due to exposure to binding **modelled constraints** (clause 50A(4)(c))

        1.1 We identified times of export constraints binding and times of import constraints binding in the **counterfactual**. These are the periods of primary benefit we determined under clause 50A(4)(b) as applying to benefits due to price changes.

[22] As well as any adjustments under 50(5), for example where prices do not reflect the capital cost of new generation (see section 9 of Chapter 7 (BBC Allocations) for more detail).

1.2 We calculated the exposure of different generating stations and load nodes to each constraint. Exposure was determined as the total quantity of dispatched generation or supplied load at times of each type of constraint binding.

1.3 We applied signs to the quantities calculated above to signal whether they indicated positive or negative benefits, based on the direction of price change expected from alleviating the constraint. For the export constraint, dispatch quantities for LSI generation were given a positive sign, supplied load quantities for LSI loads were given a negative sign, supplied load quantities for loads in the rest of the country were given a positive sign, and dispatch quantities for generation in the rest of the country were given a negative sign. For the import constraint, the opposite signs were given.

2. We calculated relative benefits due to additional quantities released by the constraint and added these to the signed numbers above (clause 50A(4)(d))

2.1 We summed the total dispatched quantities in the **factual** for each generating station and total supplied load for each load node over all time, regardless of constraints binding or not. We then repeated for the **counterfactual**. We then subtracted the **counterfactual** value from the **factual** value. In other words, we determined all periods to be periods of primary benefit as applies to benefits due to quantity changes, under clause 50A(4)(b). We considered all periods rather than just those when the constraint was binding in the counterfactual because changes in hydrological storage and risk of running out or spilling can cause a misalignment between the factual and counterfactual in the times when additional quantities are used.

2.2 We then added the signed benefits/disbenefits due to exposure to the constraint with the signed quantity changes between the **factual** and **counterfactual** (increased quantities representing benefits for any station/node, decreased quantities representing disbenefits).

156. Step 2: We then averaged across inflow sequences, weighted the results from each scenario by 50%, and summed the weighted values over the two scenarios for each generating station and load node. Applying this averaging and weighted sums here allows us to consider groups based on how the grouping would affect their allocations (see Section 4.12), and means we comply with clause 50A(6) by summing the outputs from this process to the relevant stations and load nodes within each **regional customer groups** (see Section 4.13)

Decision to use clause 50A

157. To recap, clause 50A applies if Transpower determines its application will result in **BBI customer allocations** that are broadly proportionate to **NPBs.** Clause 50B applies if Transpower determines that the application of clause 50A will not result in **BBI customer allocations** that are broadly proportionate to **NPBs.**

158. Whether clause 50A applies depends on the suitability of four assumptions in our application of 50A,

158.1 The periods of primary benefit for CUWLP are

- periods when the constraint binds in the **counterfactual**, for benefits relating to price changes
- the entire standard method calculation period, for benefits relating to quantity changes

158.2 the assumption that price changes are the same for beneficiaries either side of a constraint and across time

158.3 the assumption that benefits due to quantity changes, per unit of quantity, are the same between different customers and across time

158.4 the assumption that the benefits due to the two points above are the same as each other per unit of quantity

159. Both quantities and prices are important determinants of private benefits.

160. Price forecasting, however, is comparatively more complex and more sensitive to the input assumptions of the model. As discussed in Chapter 7 (BBC Allocation), applying clause 50A instead where broadly proportional to expected positive **NPB** limits the impact of discretion in input choices on **BBI customer allocations**, provides greater certainty for customers, is simpler, and supports a more durable TPM.

161. Given the sensitivity of prices to input assumptions, if the price outcomes from our **wholesale market model** are very different to those implied under the application of clause 50A, we would also consider if reasonable alternative assumptions could result in price outcomes consistent with clause 50A.

Periods of primary benefit.

162. The primary benefits from CUWLP arise from alleviating **modelled constraints**, either due to price changes or due to increased quantities. We have determined the periods of primary benefit as

- periods when a **modelled constraint** binds in the **counterfactual**, for benefits relating to price changes
- the entire **standard method calculation period**, for benefits relating to quantity changes

163. When constraints bind in the wholesale market, prices rise downstream of the constraint and fall upstream of the constraint. Alleviating the constraint therefore reduces downstream prices and increases upstream prices. Benefits and disbenefits due to price changes are also expected to occur at other times than the constraint binding, because of different generation build between the **factual** and **counterfactual** and as hydro storage is affected by constraints binding (as use of water is either constrained down or up, depending on the constraint) and by anticipation of constraints binding (where generators use more water to prevent spill or less water to prevent shortages, depending on which constraint they are anticipating). These factors, however, are not significant for CUWLP compared to the periods of constraints binding. Therefore, we consider the periods of the **modelled constraints** binding to be the primary periods of benefit when assessing benefits due to price changes.

164. As noted earlier in this section, for benefits relating to quantity changes we considered all periods rather than just those when the constraint was binding in the

counterfactual because changes in hydrological storage and risk of running out or spilling can cause a misalignment between the **factual** and **counterfactual** in the times when additional quantities are used. Significant benefits are expected to accrue due to quantity changes, as significant spill is avoided in *Tiwai leaves*.

165. While we consider the majority of quantity changes from CUWLP to be because of **modelled constraints** being alleviated, we note that by defining periods of primary benefit for quantity changes as the entire **standard method calculation period**, we are able to capture quantity changes due to any reason.

<u>Equal price changes either side of the constraint, between constraints, and across time</u>

166. For this assumption not to apply, we need to believe there are materially different market price changes applying to different **modelled regions,** or across time. That is, we would need to see evidence of price changes, and we would need to believe the underlying assumptions resulting in these differences are more realistic than alternate assumptions resulting in equal price changes.

167. For example, if there were a material proportion of benefits due to reducing unsupplied load, we would assume a higher per MWh benefit to the relevant load **customers**. This was not true for this case study. While some load was unsupplied due to the import constraint, the vast majority of benefits related to that constraint occurred when storage was being conserved to prevent load deficits, not when deficits were actually occurring.

168. Our modelled results (before applying 50A) do show significant differences in price changes between **modelled regions**. We have identified three factors where plausible alternative assumptions could lead to more similar price changes between **modelled regions**. These factors are:

    168.1 *Supply and Demand assumptions*. The price changes produced by SDDP for the *Tiwai stays* and *Tiwai leaves* in this case study have significantly higher price changes for generation compared to load **customers**, on average. However, as illustrated in Chapter 7 (BBC Allocation), this result is highly sensitive to the assumptions for future supply and demand, with results in the opposite direction for other CUWLP runs using different assumptions. It would be reasonable to assume a different supply demand balance either side of the constraints to what we have modelled. For example, it may be reasonable to expect more generation north of the export constraint to be taken out of service than what we have modelled following Tiwai's departure when there will be a large excess of generation regardless of the constraint. This may result in prices in the rest of the country being more sensitive to the constraint binding. We also typically don't model generation outages, which can have a significant effect on the supply-demand balance, especially during summer when the export constraint often binds and generators often take outages

    168.2 *Offer granularity*. Our market model doesn't have highly granular offers like those that exist in the wholesale market. For instance, we have one offer tranche per generator, where in the wholesale market there are many, and our offers are relatively static over time, where in the wholesale market they are highly variable. This can mean the modelled price changes (for a given set of inputs) aren't as variable as in the wholesale market. This may contribute to the comparably smaller price changes outside LSI for both import and export constraints.

168.3 *Market power*. Our model assumes perfect competition. When a constraint binds there is less competition on each side of the constraint, which can have a significant impact on prices. For this case study, greater price changes were seen in LSI compared to the rest of the country for export constraints. But as market power to LSI generators will increase at times of the constraint binding, they may set a higher price, reducing the size of the LSI price change from what we've modelled.

170 While the modelled price changes differ between **modelled constraints**, there is no particular reason to expect they should. It is reasonable to assume the price in the **factual** will be higher during dry periods when the import constraint binds in the **counterfactual**, compared to wet periods when the export constraint binds, but this doesn't necessarily affect the magnitude of price change as that depends also on the prices in the factual in each of the **modelled regions**.

171 It is reasonable to expect the price changes due to alleviating the **modelled constraints** to be similar over time as they depend on the supply demand balance which is likely to be relatively stable around an equilibrium. If prices fall due to excess supply, additional load might be added or generating plant might be taken out of service, and if prices rise due to a shortage of supply, we might see increased generation build or load plant exiting the market.

<u>Equal per unit benefit for quantity changes between beneficiary groups</u>

169. The vast majority of quantity changes modelled in this case study were increases in dispatch to LSI hydro generators in the TWI leaves scenario, as would be expected to occur when alleviating the export constraints. Because the different hydro generators will have similar costs and will be dispatched at similar times, therefore receive similar prices, we would expect their benefits from increased dispatch would be similar.

<u>Benefits due to price changes similar to benefits due to quantity changes, per unit</u>

170. We expect some variance in prices during times of constraint binding depending on how 'wet' or 'dry' the hydrological conditions are. This, however, doesn't imply a variation in price changes across the constraint.

171. The economic benefit due to price changes is equal to the price change multiplied by the volume exposed to the price change. The economic benefit due to increased dispatch is the economic surplus to the producer, for a hydro generator with zero cost this is equal to the price in the **factual** multiplied by the increased dispatch quantity. The total additional quantity of hydro generation used in the **factual** represents the amount of spill that is expected to be saved due to the investment. At times of spill, the price in the factual is likely to be lower than usual. It is therefore reasonable to assume this price is similar on average to the price changes due to alleviating the constraints; i.e. it is reasonable to assume similar benefits per unit of quantity for price changes as for quantity changes.

172. *<u>In conclusion, allocations are broadly proportionate to NPB</u>*

173. We have applied clause 50A for this case study because we have determined that its application will result in **customer BBI allocations** that are broadly proportionate to **NPBs** as follows:

173.1 We have identified beneficiaries and periods of benefits based on marginal pricing principles that apply in the wholesale market

173.2 While clause 50A requires some assumptions about price effects, we have shown these assumptions are reasonable,

173.3 Forecast quantities are less sensitive to input assumptions than prices. We have used quantity outputs directly from our wholesale market model.

173.4 50A does not account for the impact of downstream transmission constraints on the allocations (e.g. the HVDC). However, we have found the change in price over the HVDC is less significant than the change either side of the CUWLP constraint. Furthermore, over time, the HVDC constraints would be expected to be at least partially relieved with either transmission or generation investments if they were material.[23]

173.5 We note that differences in quantities between different **beneficiaries** are more important determinants of benefits than price effects, because quantities can differ significantly between customers and across time. Apart from quantity differences between modelled regions, the important quantity differences between customers within a region will be captured by separating customers into **regional customer groups,** as described in the following section.

4.12 Identifying regional customer groups (50A(3))

174. This section outlines how we determined **regional customer groups.** Section 5.10 described how we determined the **modelled regions. Regional customer groups** are supply and demand sub-groups within the **modelled regions**.

175. We assessed regional supply and demand sub-groups using the relative benefits at a nodal level, as calculated per the previous section.

176. Within a region, a supply or demand sub-group is a group of supply or demand **customers** who are expected to have similar benefits to each other but have different benefits to other supply or demand **customers** within the same region.

177. We took three factors into account:

- Comparing the total exposure benefits (accounting for both times of constraint binding in the **counterfactual** and quantity changes over time between the **factual** and **counterfactual** – see previous section) to total discounted quantity (dispatched or consumed over the **standard method calculation period**) in the **factual**. This is a measure of their benefit quantity compared to their normal quantity, as determined by the **wholesale market model**. In other words, are they dispatched or consuming at times of benefit a lot in comparison to how much they are dispatched or consuming when unconstrained?
- Comparing the total discounted quantity in the **factual** to their historical **intra-regional allocators** for industrial loads compared to other loads if the above metric puts them in the same group. This is because the modelled quantity for

[23] Noting the North Island is a sufficiently large region that grid-scale generation is a credible alternative to mitigate the constraint, which may not be the case for smaller regions.

non-industrials will account for load growth, but the allocators are based on historical volumes, meaning if they were grouped together then industrial loads allocation would incorporate part of the load growth benefits of other **beneficiaries**.

- A need to reduce false precision. The need to reduce false precision is especially relevant:
  - for non-industrial loads, because we consider forecasts at an aggregate level to be more precise, as discussed in Chapter 7 (BBC Allocation).
  - where we see large differences in modelled benefits between generators that have slightly different input assumptions and the model has dispatched one significantly more than another (determinacy/sensitivity).

178. We have only created **regional customer groups** where the group has a positive net private benefit, because the **individual NPBs** used to determine **customer allocations** are calculated for positive net private benefits only (clause 48). The groups that had net positive benefits were:
    - In 'Lower South Island', 'Direct connect generation' and 'Tiwai load'
    - In the 'Rest of country', 'Direct connect peakers', 'Direct connect industrial', and 'All other offtake'.
179. We have set off market benefit and disbenefit arising in respect of a **customer** with generation and load at the same connection location, in accordance with clause 47. We summed benefits between the different generating and load plant at a connection location because **customer**'s contracts and their **intra-regional allocators** are specified at the connection location rather than plant level.
180. **Customers** with positive benefits are called **beneficiaries.**
181. All peaking plant have net positive benefits when considered on their own without summing with other plant at the same location.
182. All thermal commitment plants have net positive benefits when considered on their own, except for Huntly's combined cycle plant which has significant disbenefits. The algorithm has systematically and repeatedly dispatched these plant very differently because they are often at or close to the margin meaning the cheaper plant (Huntly's combined cycle plant) has been dispatched very significantly more often than the other plant, despite all thermal commitment plant's costs and dispatch constraints being very similar. The other thermal commitment plant has therefore been predominantly only needed for very dry periods, when they are benefitting from the import constraint binding, and not during periods where E3P is dispatched, perhaps constrained on, when they are disbenefitting from the export constraint binding. Because thermal commitment plants are often close to the margin their dispatch is highly dependent on the generation build/retirement assumptions and the accuracy of our cost assumptions. Moreover, we would expect in the real market where prices are above operational cost that plant with similar operating cost would be dispatched similarly. For these reasons we have grouped all thermal commitment plant together, resulting in disbenefits overall for the group.

183. Stratford generation site has both thermal commitment and peak plant. These plants, when considered on their own, each deliver positive benefits. However, because thermal commitment plants deliver significant disbenefits when considered as a group, and because peaking plants' positive benefits are comparatively very small in magnitude, we have determined that the net benefit at Stratford should be considered negative when summed across plant.
184. No transmission customers in LSI with embedded generation had positive net benefits, as the disbenefits accruing to their load were more than the benefits accruing to heir generation.
185. All LSI generators were hydro generators and so benefitted similarly according to our model, except for Waipori (at Berwick), who appeared to benefit substantially less. This was determined by comparing their benefits as a proportion of the total generation benefits in LSI and comparing to their total modelled dispatch as a proportion of the total modelled dispatch in the group in the **factual**. Our preference is not to group individual plant into their own group unless we are confident the difference in their benefits compared to others is not caused by false precision in our modelling. At this time, we are not clear why benefits for Waipori would be significantly different from other hydro generation in the region, therefore, for the purpose of this case study, we have grouped them into the same group. However, we would need to investigate this relationship further before determining final allocations for this **BBI**.
186. We note that had there been injection benefits in the LSI attributable to other types of generation, we would expect these to be grouped separately from the LSI hydro generation, as LSI hydro generation would be expected to benefit more from CUWLP compared to other types of generation.
187. All loads in the 'Rest of country' region have net positive benefits. All loads appear similar in terms of benefits when comparing their benefits as a proportion of the total load benefits in the **modelled region** and comparing to their total modelled consumption as a proportion of the total modelled consumption in the region in the **factual**.
188. However, when assessing industrials as a group against all other loads, and comparing this to their **intra-regional allocators**, non-industrials benefit more as a proportion of their historical consumption, compared to industrials, as their demand is expected to grow over time. Direct connect industrials have therefore been put in their own group because otherwise they'd be paying a share of the benefits attributable to other loads' growth. These have been identified as direct connect industrials at non-conforming nodes (nodes in the wholesale market system which are sufficiently large and difficult for an independent operator to forecast that participants at those nodes are required to provide their own forecasts).
189. Note, in determining net benefits at the location level prior to determining these regional sub-groups, we needed to make several assumptions which may have affected groupings and the relative benefits assigned to each group. The **wholesale market model** we used for indicative pricing did not always model separate loads for each **customer**. For these nodes we apportioned benefits according to their relative offtake **intra-regional allocators** (see Section 4.14). We also needed to assign modelled embedded generation to the right **customer** and location, or sometimes apportion between **customers**. There were also instances where we noticed generation or load

had been mapped to slightly different locations where the actual point of service was not modelled. We intend to review this process prior to final pricing.

4.13 Determine PVRNPB (49)

190. This section describes how we determined **PVRNPBs** using the relative benefits calculated at the nodal level (Section 4.11) and our **regional customer groups** (section 4.12). To recap, the **PVRNPBs** are the present values of **NPBs** for each **regional customer group**.
191. **PVRNPBs** are used alongside **intra-regional allocators** (Section 4.14) to determine **individual NPVs**. Because **individual NPBs** are only calculated for connection locations where a customer has positive **NPB** (clause 48), we only identified groups with positive net private benefits (see Section 4.12). These were all direct connect generation in LSI (Lower South Island Direct connect gen), Tiwai load (Lower South Island Tiwai load), direct connect industrial load in the rest of the country (Rest of country Direct connect industrial), and non-industrial offtake in the rest of the country (Rest of country all other offtake), and direct connect peaking plant excluding Stratford peakers in the rest of the country (Rest of country Direct connect peakers).
192. To recap, our approach under clause 50A(4) is to calculate relative benefits for each scenario – *Tiwai stays* and *Tiwai leaves*, before weighting these 50-50%. Because the price changes to each beneficiary are assumed to be similar, the relative benefits we calculate for each group are their total consumption/production at times of the **modelled constraints** binding in the **counterfactual**, plus any increase in consumption/production between the **factual** and the **counterfactual**.
193. For Tiwai, we make an exception to the 50-50% weighting between scenarios, instead basing their relative benefits on *Tiwai stays* only, as required by clause 46(3).
194. We note that CUWLP was not determined as a **reliability BBI**, **ancillary services BBI**, and/or **other BBI**. We therefore do not need to add the **individual NPBs** calculated in this case study under the **market BBI** framework to any **individual NPBs** calculated under the other frameworks. This means, as per clause 50A(8), we have not converted the **market regional NPBs** into dollars.
195. We have applied clause 49(2) by using discounted quantities in the process of finding the **market regional NPBs**, meaning the **PVRNPB** is the same as the **market regional NPB.**
196. The table below shows the **PVRNPB** for the **beneficiary** groups.

Table 3 beneficiary groups by regions, the present value of regional net private benefits (PVRNPB), and allocation

Region	Sub-group	PVRNPB(GWh)	Allocation %
Lower South Island	Direct connect gen	31183	21.73
Lower South Island	Tiwai load	7709	5.37
Rest of country	Direct connect peakers	113	0.08
Rest of country	Direct connect industrial	4857	3.38
Rest of country	All other offtake	99656	69.44

197. Note, we have not included the effect of changes in the loss and constraints excess as these effects are not included in the application of clause 50A, which we have used to calculate **market RNPB**.

4.14 Intra-regional allocators (63)

198. This section describes how we determined **intra-regional allocators** (**IRAs**) for each **customer** in the **regional customer group**.

199. **IRAs** are required to calculate **individual NPBs**, as described in the following section.

200. Clause 63 defines the **IRAs** to be used for a **BBI**. Under the **price-quantity method**, the **IRA** for **offtake customers** can be either mean historical **offtake**, or mean historical **coincident peak offtake**. The **IRA** for **injection customers** is always mean historical **injection**.

201. For this **BBI**, the mean historical **offtake IRA** has been chosen for **offtake customers** because the benefits from CUWLP do not only occur during peak periods. The benefits from CUWLP arise by alleviating constraints. The constraints are driven by hydrological conditions, either high inflow periods for the export constraint, or dry periods for the import constraint. These conditions last more than a day, meaning the constraint doesn't bind any more during daily peak periods than other periods. The export constraint in the Tiwai leaves scenario, which dominated the expected benefits, is expected to bind all through the year but more so in late spring and early summer when inflows in the LSI region are typically at their highest, due to snow melt.

202. As specified in clauses 63(5) and (6), where a **regional customer group** under the **standard method** has mean historical **offtake** or **injection** as its **IRA**, the **IRA** is calculated as the **customer's** average annual **offtake** or **injection** for all **GXPs/GIPs** in the **regional customer group**, based on the five complete **pricing years** immediately preceding the **final investment decision date** (30 June 2020), which is the period from 1 September 2014 – 31 August 2019. For this case study, we have used the period 1 September 2015 – 31 August 2020 to save on processing time by using the same period as we used for the WUNIVM case study. We expect the allocators taken over this period will be similar to those based on 1 September 2014 – 31 August 2019.

203. As specified in clauses 64 and 80(3)(a), we have estimated the **IRA** for the two **recent customers** in the **regional customer group** as if they were a new **customer:**
   - OMV at Motunui: we have assumed this plant has the same load factor as Kupe at Hawera because both produce LPG. OMV's maximum demand is 13 MW which at 70% load factor would offtake approx. 79.2 GWh p.a.
   - Todd Generation Taranaki at Junction Road: we have assumed this plant has the same average **injection** as McKee (310.1 GWh p.a.) because both stations are open cycle gas stations with the same capacity (100 MW).

204. For the purpose of this case study, we have treated Norske and Kawerau Geothermal as a single **customer** consistent with their historical agreement which ended 31 April 2021.

205. For each group we first identified the relevant customer points of connection.

- For LSI direct connect generation, these customer points of connection (PoCs) included Meridian at Manapouri, Contact at Clyde and Roxburgh, and Trustpower at Berwick.
- For Rest of Country Peakers, these PoC's included Todd at McKee and Junction Road, and Contact at Whirinaki.
- For Rest of Country Direct Connect Industrials, these include Winstone Pulp at Tangiwai, PanPac at Whirinaki, PowerCo at Kinleith, and New Zealand Steel at Glenbrook.
- For Tiwai offtake, this is New Zealand Aluminium Smelters at Tiwai.
- For Rest of Country All Other Offtake, these included all customers who offtake more than they inject at Twizel, Naseby, and all points of connection electrically north.

206. We then used these groupings to identify **IRAs** applicable to each **regional customer group**.

4.15 Individual NPBs, customer allocations and benefit-based charges (36, 43, 48)

207. This section details how we determined **Individual NPBs** using the **IRAs and PVRNPBs**, **customer allocations (CAs)** using the **Individual NPBs**, and **BBCs** using the **CAs** and **covered costs**.

208. Table 4 below shows the **individual NPBs**, **CAs**, and **BBCs** for 2030 when the **covered cost** is expected to peak at $9.5 million for the pricing year.

209. Clause 48 defines **individual NPB** as the **PVRNPB** multiplied by the **customer's IRA** as a proportion of all **customer's IRA** for that **regional customer group.**

210. **Customer allocations** are calculated as the **customer's individual NPB** divided by the sum of all **individual NPBs** (clause 43), noting that **individual NPBs** are only calculated for each **customer** based on positive **regional NPBs** at a **point of connection** (clauses 44(2)(c), and 48).

211. Note that customer allocations are fixed over the lifetime of the investment, except to the extent they are adjusted when new customers or large plant enter or exit.

212. We estimated a covered cost of $9.5 million for the 2030 pricing year, based on the method described in Section 4.1.

213. **BBCs** are calculated for the 2030 pricing year by multiplying the **covered cost** by the **beneficiary's BBI customer allocation** (clause 36).

Table 4 CUWLP benefit-based investment, allocations and charges

Customer	RCPD allocation	RCPD charge	BBC allocation	BBC charge
Alpine Energy	1.64%	$111,746	2.02%	$191,638
Buller Electricity	0.09%	$6,391	0.10%	$9,715
Centralines	0.32%	$22,032	0.30%	$28,115

Customer	RCPD allocation	RCPD charge	BBC allocation	BBC charge
Counties Power	1.71%	$116,303	1.43%	$135,811
Contact Energy	0.01%	$682	9.18%	$872,254
Aurora Energy	3.01%	$204,448	-	-
Electricity Ashburton	0.73%	$49,649	1.24%	$117,871
Eastland Energy	0.90%	$61,096	0.74%	$69,858
Genesis Power	0.00%	$8	-	-
Electra	1.01%	$68,555	0.66%	$62,983
Horizon Energy	0.18%	$12,134	0.92%	$87,546
Whareroa Cogen	-	-	-	-
Beach Energy Resources	0.14%	$9,433	0.15%	$14,593
Marlborough Lines	1.04%	$70,644	0.99%	$93,616
MEL (Te Apiti) Ltd	0.00%	$110	-	-
MEL (West Wind) Ltd	0.00%	$182	-	-
Meridian Energy	0.01%	$807	12.26%	$1,164,455
Methanex NZ	0.09%	$5,876	0.12%	$11,808
Mainpower	1.62%	$110,053	1.59%	$151,030
Mercury NZ Ltd	-	-	-	-
Mercury SVP Ltd	-	-	-	-
Nga Awa Purua Joint Venture	-	-	-	-
Nelson Electricity	0.16%	$11,188	0.26%	$24,700
Northpower	2.38%	$161,819	2.70%	$256,512
Ngatamariki Geothermal	-	-	-	-
NZ Aluminium Smelters Ltd	9.78%	$665,003	5.37%	$510,287
BHP NZ Steel	0.14%	$9,847	1.02%	$97,327
OMV NZ Production Ltd	0.17%	$11,431	0.20%	$18,952
Orion	9.85%	$669,982	8.33%	$791,433
Pan Pac Forest Products	0.30%	$20,424	1.00%	$94,536
Powerco	13.06%	$888,058	10.63%	$1,010,184
Powernet	3.48%	$236,868	0.40%	$37,753
Daiken Southland Ltd	0.11%	$7,282	-	-
Scanpower	0.22%	$14,928	0.21%	$19,696
Southdown Cogeneration	0.00%	$206	0.00%	$339
Southpark Corporation	0.00%	$54	0.00%	$114
Norske Skog Tasman	-	-	-	-
Resolution Developments Ltd	0.00%	$8	-	-
Southern Generation	-	-	-	-
Tararua Wind Power Ltd	0.00%	$66	-	-
Network Tasman	1.77%	$120,158	1.58%	$149,833
Nova Energy	-	-	-	-

Customer	RCPD allocation	RCPD charge	BBC allocation	BBC charge
Todd Generation Taranaki Ltd	0.00%	$62	0.08%	$7,426
Top Energy	0.68%	$45,921	-	-
KiwiRail Holdings Ltd	0.15%	$10,255	0.12%	$11,418
Trustpower Generation	0.00%	$1	0.30%	$28,812
Wellington Electricity	7.90%	$536,941	5.68%	$539,247
Unison Networks	4.15%	$282,058	3.27%	$310,738
Vector	27.25%	$1,852,890	21.55%	$2,047,183
Waipa Networks	1.12%	$76,026	1.02%	$97,029
Network Waitaki	0.53%	$35,918	0.68%	$64,137
Waverly Wind Farm Ltd	-	-	-	-
WEL Energy	3.12%	$212,269	2.43%	$230,594
Winstone Pulp International	0.38%	$25,818	0.50%	$47,283
Westpower	0.22%	$15,109	0.34%	$32,107
The Lines Company	0.58%	$39,261	0.64%	$61,068

Table 4 shows two effects of the proposed TPM:

214. Table 4 shows two effects of the proposed TPM:

214.1 the change in allocation methodology, which results in charges shifting to Lower South Island generators from offtake customers (especially offtake customers in the Lower South Island who – except for NZ Aluminium Smelters – receive no charge). The proportion of charge each offtake customer receives also reflects the change from RCPD to a historical average offtake allocation metric.

214.2 the explicit attribution of all opex to **BBIs**: Table 3 shows only the first-order impact of the **BBI** on charges under the proposed and existing TPMs, but not the decrease in the residual charge and other BBCs following the commissioning of this **BBI** due to there being more assets over which to recover opex. Furthermore, for charges under the existing TPM, Table 3 shows only the incremental increase associated with capital costs, not incremental opex due to the **BBI**. To avoid doubt , the TPM does not impact the total revenue Transpower recovers, and therefore the $2.7m difference between the total charges attributed to the **BBI** shown in Table 3 under the existing and proposed TPM is a difference in attribution of charges, not a difference in total charges/revenue.

TRANSPOWER

Appendix E: BBC Resiliency method case study - WUNIVM Waikato dynamic reactive device

30 June 2021

Contents

1 Introduction

1. This appendix presents the results of an indicative pricing case study for the first component of the Waikato and Upper North Island Voltage Management (**WUNIVM**) project: the ±150 MVAr dynamic reactive device located in the Waikato. The purpose of this example is to illustrate the application of the resiliency method, which is a benefit-based charge (**BBC**) standard method in the proposed TPM.
2. The proposed TPM will not be formally applied to this project until after the new TPM has been approved and finalised by the Authority. Hence the allocations and pricing in this case study are indicative only and subject to change.
3. We note that the regulatory processes governing investment decisions (the Capex IM) are different from the regulatory processes governing pricing (the TPM). Therefore, this appendix is not intended to explain the background and need for investment in as much detail as is necessary for the investment decision. Please refer to the major capex proposal for more information[1].
4. The TPM and investment decision making processes are governed by two separate regulatory processes. The Commerce Commission regulates the way in which decisions are made to invest in the grid, including through determining, and on a regular basis reviewing, the Transpower Capex IM (Capex IM) and approving Transpower's proposed capital spend. The Capex IM comprises the rules and processes for approving capital expenditure (Transpower's applications and the Commission's assessments), including the Investment Test that we must apply to our major capex investments over $20 million in order to recover costs through the TPM. Once Transpower's capital expenditure proposal has been approved by the Commission, whether as major capex or base capex, that spend may be recovered as allowable revenue through the TPM. As the Commission stated in its recent approval of our Bombay Otahuhu Regional major capex project (MCP):

> The new TPM guidelines and the new TPM Transpower develops under them will not affect the regulatory approval process for assessing the MCP under the Capex IM or the amount Transpower can recover in transmission charges for the investment.[2]

[1] Waikato and Upper North Island Voltage Management Investigation | Transpower

[2] Commerce Commission Decision and reasons on Transpower's Bombay Otahuhu Regional MCP, 19 March 2021

2 Background to the project

5. Consultation and approval for cost recovery for stage 1 of WUNIVM, including the Waikato dynamic reactive device, has been completed in accordance with the Capex IM:
   - Consultation for the WUNIVM project was undertaken in July 2016 (long-list consultation), and June 2019 (short-list consultation)
   - We sought approval for stage 1 of the project in December 2019
   - In September 2020, the Commerce Commission approved cost recovery for up to $143m for stage 1 of the project[3]
   - In November 2020, we committed to the first component of the approved project: a ±150 MVAr dynamic reactive device in the Waikato, with a target commissioning date of prior to winter 2023.[4]
6. The purpose of the project is to maintain voltage in the Waikato and Upper North Island, and ultimately the entire North Island, as thermal generation exits the region and load grows. Maintaining voltage is needed to protect the security of the power system by preventing the voltage from falling too low or rising too high. If the voltage gets too high it can cause damage to consumer equipment, injure people, and trip generators which can ultimately result in cascade failure of the power system. If the voltage gets too low generators may trip, also leading to cascade failure of the power system.
7. There are several inter-related voltage management issues mitigated by the project components, including:
   - Transient under and over-voltage: a very fast (e.g. milliseconds) voltage excursion that occurs immediately following a system fault during peak load periods (e.g. a lightning strike on a transmission line)
   - Long-term voltage collapse: a slow (several seconds to minutes) collapse in the system voltage following a transmission or generation asset being removed from service during peak load periods
   - High steady-state voltage: high voltage with all assets in service. This usually occurs during low load periods when lightly loaded transmission assets are producing more reactive power.
8. We expect transient and static issues to arise during peak load periods if there is a major reduction in capacity at Huntly, and/or if peak loads grow in the region as is forecast. High steady-state voltage issues exist today during low load periods and are presently mitigated by temporarily removing circuits from service. Through our options assessment and consultation processes, we proposed the following components to manage these voltage issues in stage 1 of the project:

---

3 Commerce Commission Decision and reasons on Stage 1 of Transpower's Waikato and Upper North Island Voltage Management staged MCP, 23 September 2020

4 Work on voltage management project to commence | Transpower

- Two ±150 MVAr dynamic reactive devices: one in the Upper North Island and the other in the Waikato
- A post-fault demand management scheme in the Waikato and Upper North Island
- Preparatory works for stage 2 of the project, including additional investigation, consultation, obtaining property rights and environmental approvals, design work and non-binding tendering for future series capacitors and installation works on the BHL-WKM 1&2 transmission line.

9. Stage 2 of the project is the procurement, installation, and commissioning of series capacitors on the BHL-WKM 1&2 transmission lines. We have not yet sought approval for stage 2 from the Commerce Commission.
10. At the time of writing, only the Waikato dynamic reactive device (the subject of this case study) has been committed. The other project components are independent investments able to be delivered separately from the Waikato dynamic reactive device. Therefore, we have classified the Waikato dynamic reactive device as a separate BBI, rather than including all components in WUNIVM project as a single BBI.[5]

3 Explaining indicative benefit-based charges

11. This section presents the indicative BBC allocations and prices for this case study and describes how these are broadly proportional to expected positive net private benefits (**EPNPB**s), as required by clause 8 of the Guidelines.
12. We note the BBC allocations and prices in this case study are indicative of the prices that would result under the new TPM the form of which will be confirmed by the Authority following its consultation.
13. Based on this case study we have drawn the following conclusions and observations about resiliency method allocations for this BBI under the proposed TPM:
    - For a BBI which is primarily undertaken to mitigate cascade failure, the charges are allocated in proportion to offtake in the island in which the fault is being mitigated, despite the investment being caused by more regional issues (e.g. changes to demand and generation in the Waikato and Upper North Island). We consider these charges are consistent with clauses iv and 8 of the Guidelines, which require charges are recovered from those who are expected to benefit from an investment, not attributed to the causer of an investment.
    - Compared to the existing TPM, charges are generally higher for North Island offtake customers because South Island offtake customers would not receive any allocation for this BBI under the proposed TPM. Injection customers are unaffected because they are not charged for this type of capital investment under either the existing TPM (through the interconnection charge) or the proposed TPM. We consider this broadly proportional to EPNPB because the large difference between the value of lost load (~$20k/MWh in the Code) and

[5] Section 4.1 explains other reasons for classifying the Waikato dynamic reactive devices as a separate BBI.

the per MWh operating profit of generation (of the order of $100/MWh), means any benefit to generators would be disproportionally low compared to the benefit to loads.

- The proposed TPM allows for projects to be split into separate BBIs. We expect the WUNIVM project components to be commissioned at different times and have different beneficiaries, and therefore have classified the Waikato dynamic reactive device as a separate BBI to other project components. As a result, this case study is only illustrative for the first component of the WUNIVM project, the dynamic reactive device in the Waikato (approx. $60m of the $143m cost for stage 1 of the project).

3.1 Indicative prices for Waikato dynamic reactive device

14. As specified in clause 36(2) of the proposed TPM, a customer's benefit-based charge for a BBI is equal to its covered cost for a given pricing year multiplied by the customer allocation.
15. Table 1 shows the indicative intra-regional allocators, customer allocations, indicative charges under the proposed TPM in 2030 (when covered cost is estimated to peak), and estimated charges for the BBI under the existing TPM.[6]
16. We have not shown customers with an estimated charge of less than $1k p.a. under the proposed and existing TPM, which has had the effect of removing most generation customers who tend to have small volumes of offtake, and very small North Island offtake customers (e.g. Southpark).
17. **Error! Reference source not found.** shows two effects of the proposed TPM:
    - the change in allocation methodology, which results in charges shifting from South Island to North Island offtake customers, as well as due to the change from RCPD to a historical average offtake allocation metric.
    - the explicit attribution of all opex to BBIs: Table 1 shows only the first-order impact of the BBI on charges under the proposed and existing TPMs, but not the decrease in the residual charge and other BBCs following the commissioning of this BBI due to there being more assets over which to recover opex. Furthermore, for charges under the existing TPM, Table 1 shows only the incremental increase associated with capital costs, not incremental opex due to the BBI. To avoid doubt , the TPM does not impact the total revenue Transpower recovers, and therefore the $1.9m difference between the total charges attributed to the BBI shown in Table 1 under the existing and proposed TPM is a difference in attribution of charges, not a difference in total charges/revenue.

[6] Using RCPD from the capacity measurement period ending 31 August 2020 (used to determine prices in the 2021/22 pricing year).

Table 1: Indicative intra-regional allocators, customer allocations, and benefit-based charges for the Waikato dynamic reactive device

	Intra-regional allocator/net-private benefit (average kWh p.a. 1 Sep 2015 – 31 Aug 2020)	Customer allocation under the proposed TPM	Indicative charge under proposed TPM in 2030 ($k)	Estimated interconnection charge attributed to BBI in 2030 under current TPM ($k)
Alpine Energy	0	0.00%	0	71
Aurora Energy	0	0.00%	0	129
Beach Energy Resources	60,999,380	0.27%	17	6
BHP NZ Steel	483,368,071	2.14%	133	6
Buller Electricity	0	0.00%	0	4
Centralines	117,522,930	0.52%	32	14
Contact Energy	4,885,856	0.02%	1	0
Counties Power	567,704,777	2.51%	156	74
Daiken Southland Ltd	0	0.00%	0	5
Eastland Energy	292,013,728	1.29%	80	39
Electra	330,859,777	1.46%	91	43
Electricity Ashburton	0	0.00%	0	31
Horizon Energy	435,128,468	1.93%	119	8
KiwiRail Holdings Ltd	47,729,800	0.21%	13	6
Mainpower	0	0.00%	0	70
Marlborough Lines	0	0.00%	0	45
Methanex NZ	49,357,517	0.22%	14	4
Nelson Electricity	0	0.00%	0	7
Network Tasman	0	0.00%	0	76
Network Waitaki	0	0.00%	0	23
Norske Skog Tasman	9,339,555	0.04%	3	0
Northpower	1,072,251,294	4.75%	294	102
NZ Aluminium Smelters Ltd	0	0.00%	0	421
OMV NZ Production Ltd	79,219,974	0.35%	22	7
Orion	0	0.00%	0	424
Pan Pac Forest Products	469,509,631	2.08%	129	13

	Intra-regional allocator/net-private benefit (average kWh p.a. 1 Sep 2015 – 31 Aug 2020)	Customer allocation under the proposed TPM	Indicative charge under proposed TPM in 2030 ($k)	Estimated interconnection charge attributed to BBI in 2030 under current TPM ($k)
Powerco	4,344,039,116	19.23%	1192	562
Powernet	0	0.00%	0	150
Scanpower	82,330,272	0.36%	23	9
The Lines Company	255,270,369	1.13%	70	25
Top Energy	158,578,513	0.70%	44	29
Unison Networks	1,299,921,533	5.76%	357	178
Vector	8,557,464,186	37.89%	2349	1172
Waipa Networks	405,594,488	1.80%	111	48
WEL Energy	963,909,264	4.27%	265	134
Wellington Electricity	2,254,116,609	9.98%	619	340
Westpower	0	0.00%	0	10
Winstone Pulp International	234,830,513	1.04%	64	16
Total		100%	$6,200	$4,300

4 How we applied the TPM for this case study

18. This section describes the processes specified within the proposed TPM that we have followed to produce indicative prices for this case study:
    - Section 4.1: classifying the BBI as **high-value** or **low-value**, and determining which method (**price-quantity** or **resiliency**) should be used to determine its **benefit-based charges** (**BBC**)
    - Section 4.2: explains the consultation requirements for this **BBI**
    - Section 4.3: the estimated **covered cost** for this **BBI**
    - Section 4.4: applies the **resiliency method** for this **BBI.**

19. In this section, all terms in bold are the terms as defined in the proposed TPM and references to clauses are to clauses of the proposed TPM (unless otherwise stated).

4.1 Classifying the BBI (clause 43)

20. The Waikato dynamic reactive device is a **post-2019 BBI** as it is an **interconnection investment** that will be **commissioned** after 23 July 2019, being the relevant date prescribed under the Guidelines. The Waikato dynamic reactive device is a **high-value BBI** because its depreciated value is expected to be greater than $20m when fully

commissioned, and therefore a **customer's individual NPB** must be calculated using a **standard method** (clause 43(2)), consistent with clause 20(a) of the Guidelines).

21. The proposed TPM defines the types of **BBI** (**market**, **reliability**, or **resiliency**). We consider the Waikato dynamic reactive device to be a **resiliency BBI**, because the investment need is primarily to mitigate cascade failure. This is because the primary purpose of this component is to mitigate transient over-voltage risks (as shown in Figure 1), which the **system operator** would not manage pre-event (as discussed below). **Resiliency BBIs** use the **resiliency method** to determine charges, rather than the **price-quantity method** used for other **high-value BBIs**.

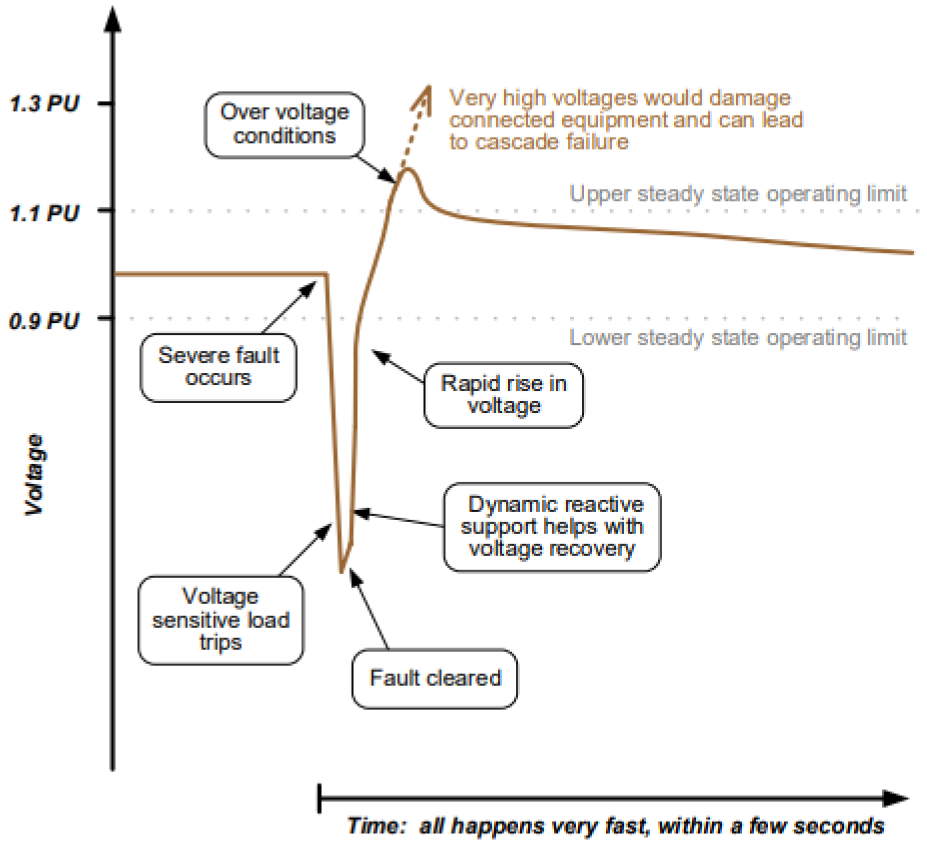


Figure 1: Transient over-voltage event

22. The transient over-voltage risk would not be managed pre-event due to its low probability (we estimate the risk of cascade failure without investment is a ~1 in 200 year event in 2024, with the likelihood increasing as regional load grows) and it in the context of mitigations available to the system operator under the Code and its Policy Statement, including available Grid owner assets, it cannot be efficiently managed pre-event. The addition of a Grid owner asset in the form of the Upper North Island Dynamic device would allow this specific system risk to be managed without inefficient pre-event mitigations such as load management.

23. Because the risk would not be managed pre-event there would be no security constraint applied in the market and no impact on **wholesale market** prices, and therefore we do not consider the Waikato dynamic reactive device to be a **market BBI**.

24. We note the other major components in the WUNIVM stage 1 and 2 projects mitigate different system needs and have different benefits than the Waikato dynamic reactive device:
    - as well as provide transient under and over voltage support, the Upper North Island dynamic reactive device would materially increase static voltage collapse load limits into the Upper North Island,[7] and
    - the series capacitors increase thermal limits into the Upper North Island, and also reduce transmission losses in the area.
25. Benefits relating to static voltage and thermal limits, and loss benefits will be realised as **wholesale market** price effects that are not related to avoiding cascade failure or a **HILP event**, and therefore these components may be assessed as a **market BBI** under the proposed TPM. As a result, the **beneficiaries** of these other project components may be different than for the Waikato dynamic reactive device. Because the **beneficiaries** may be different, we have defined the Waikato dynamic reactive device as a separate **BBI** (rather than including all components in WUNIVM project as a single **BBI**).
26. We note that while the primary benefit of the Waikato dynamic reactive device is to manage transient voltage risks, it also has secondary benefits that factored into the investment decision. In particular, it will help the system operator to manage high steady state voltages during low load periods. We consider this a secondary benefit because high steady state voltages can usually be managed using a different transmission component called a reactor, which is considerably cheaper than a dynamic reactive device. In other words, if we were only trying to mitigate high steady state voltages then it is unlikely we would invest in a dynamic reactive device.

4.2 Consultation on transmission charges (clause 17)

27. Clause 17 of the proposed TPM specifies the consultation requirements for a **BBI** relevant to setting the **BBC** for a **BBI**.
28. Because this component will be commissioned after June-2019 but was committed before the proposed TPM will come into effect, we have not conducted consultation on the benefit-based allocations for this component. We will do this after the new TPM has been confirmed by the Authority and prior to setting the charges for this **BBI** (consistent with clause 5 of the Guidelines).

4.3 Estimated covered cost and attributed opex (clauses 40-41)

29. As shown in Figure 2, we estimate the forecast **covered costs** for this **BBI** will initially plateau at approx. $6 million per annum (nominal). We have calculated the **covered cost** (including the **attributed opex**) in accordance with clauses 40 and 41 of our proposed TPM and based on the following assumptions:
    - A forecast capital cost of $60m and **commissioning** in April 2023

[7] The existing Upper North Island Voltage Stability constraint applied in the market is a static voltage stability constraint.

- Forecast **depreciation** of $1.9m p.a. based on an estimated average accounting life for the assets that make up the project of approx. 32 years
- Constant vanilla WACC of 4.57% p.a. based on Transpower's RCP3 WACC
- **Attributed opex** of $1.9m p.a., using a constant forecast **attributed opex ratio** of 1.01 based on the forecast ratio for RCP3

30. We have used assumptions to estimate the **covered cost** for this **BBI** because – under the proposed TPM – the **covered cost** is based on actual costs incurred and regulatory settings, which aren't known until after a **BBI** is **commissioned** and change over time. In particular, actual **covered cost** and **customer** charges would be calculated on the actual (rather than forecast) capital cost of the project, actual **depreciation** and the respective WACC and **attributed opex ratio** applicable to each pricing year until this investment is fully depreciated.

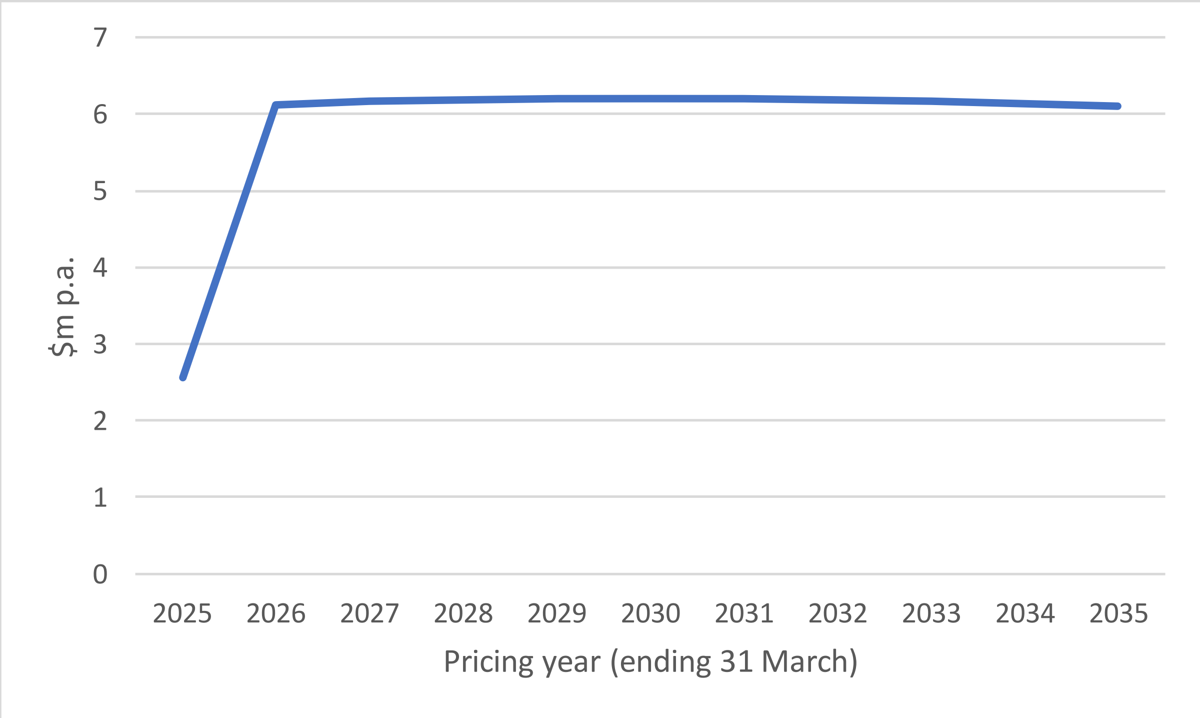


Figure 2: Estimated covered cost from 2025-2035 (nominal)

4.4 Resiliency method (clauses 54-56) and intra-regional allocators (clause 63)

31. As specified in clause 43(1) of the proposed TPM, a **beneficiary's customer allocation** is equal to their **net-private benefit** (NPB) as a proportion of all **beneficiaries'** NPB for a given **BBI**.
32. For **resiliency BBIs**, the NPB for each **beneficiary** is equal to each **customer's intra-regional allocator** (IRA)[8] (clause 55).
33. The Waikato dynamic reactive device mitigates cascade failure in the North Island because the system faults being mitigated occurs in the North Island. Therefore, as

[8] The IRA is a measure of historic demand or injection used to determine the charges allocated to individual customers as a proportion of the charges allocated to the regional customer group.

specified in clause 56 of the proposed TPM, the **modelled region** is the North Island and the **regional customer group** is all **offtake customers** in the North Island. As explained in the **BBC** reasons paper, there is no **regional customer group** for **injection customers** because the value of lost load is much greater than the lost operating profit of a generator.

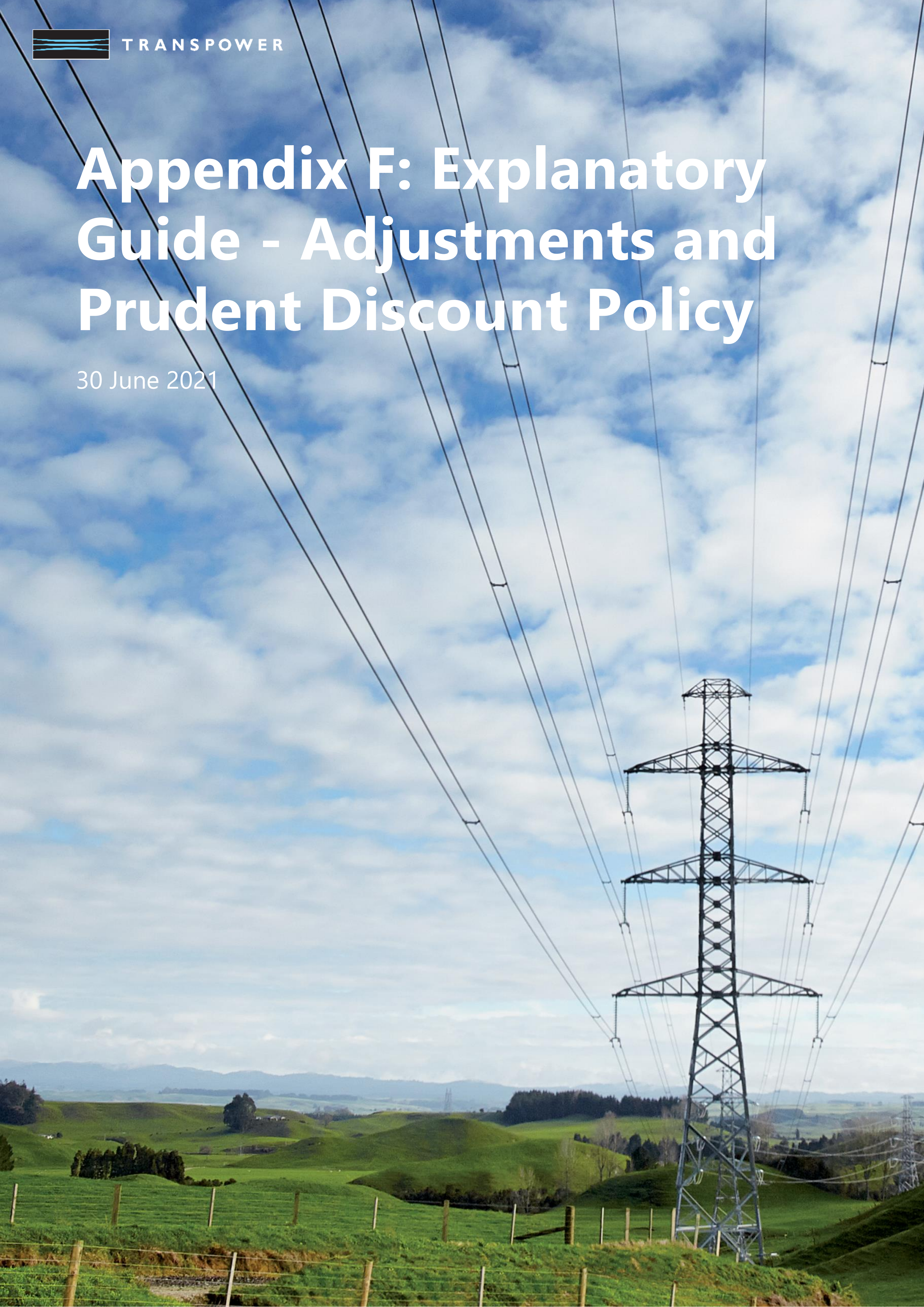
34. The IRA for the **resiliency method** is mean historical annual **offtake** (clause 63(3)).
35. As specified in clause 63(5), where a **regional customer group** under the **standard method** has mean historical **offtake** as its IRA, the IRA is calculated based on the **customer's** average historical annual **offtake** for all **GXPs** in the **modelled region** in the five complete **capacity years** before the **final investment decision date** (November 2020) for the Waikato dynamic reactive device (1 September 2015 – 31 August 2020).[9]
36. If a **beneficiary** has more than one **point of connection** at a **connection location**, we have combined its **offtake** and **injection** in each trading period to calculate a net **offtake** or **injection** for that **beneficiary** at that **point of connection** (clause 10(i)).
37. As specified in clauses 64 and 80(3)(a), we have estimated the IRA for the one **recent customer** in the **regional customer group** as if they were a new **customer:**
    - OMV at Motunui: we have assumed that this plant has the same load factor as Kupe at Hawera because both produce LPG. OMV's maximum demand is 13 MW which at 70% load factor would offtake approx. 79.2 GWh per year.
38. For the purpose of this case study, we have treated Norske and Kawerau Geothermal as a single **customer** consistent with their historical agreement which ended 31 April 2021.
39. Table 1 in Section 3 above shows the **intra-regional allocators** for this case study.

[9] See the definition of capacity measurement period in the proposed TPM.

TRANSPOWER

Appendix F: Explanatory Guide - Adjustments and Prudent Discount Policy

30 June 2021



Contents

1 Introduction

1. The purpose of this appendix is to assist the Authority and other stakeholders to better understand our proposals for:

    1.1 adjustments to benefit-based charges (**BBCs**) and residual charges, and

    1.2 recovery of stand alone cost prudent discounts (**SACPDs**).

2. We have prepared this explanatory guide in response to a number of requests from stakeholders in submissions received during the course of our TPM consultation that we prepare an explanatory guide demonstrating how adjustments to customers' transmission charges will occur in practice.

3. In this explanatory guide, we have prepared a simple, stylised worked example that uses fictitious charges for a set of hypothetical customers, regions and connection locations (**Worked Example**). The Worked Example is explained in detail in part 2.

4. The purpose of the Worked Example is to step-through the provisions in the proposed TPM drafting (**proposed TPM**) that address adjustments to benefit-based charges and residual charges payable by customers for each of the following scenarios:

    4.1 new load customer joining (part 4);

4.2 existing grid-connected customer exits completely (part 5);

4.3 embedded generator connecting to a distribution network (part 6);

4.4 existing customer disconnecting from a connection location (but remaining connected at another connection location (part 7);

4.5 substantial and sustained change in grid use (**SSCGU**) (part 8); and

4.6 recovery of a SACPD prudent discount from other customers (part 9).

5. The Worked Example is supported by a separate spreadsheet “TPM – Adjustments and PDP – Worked Example Spreadsheet” (**Worked Example Spreadsheet**). The Worked Example Spreadsheet contains calculations showing the adjustment to the customers’ transmission allocations for each adjustment scenario. Where any figures are included in a table in this explanatory guide, these figures have been taken from the Worked Example Spreadsheet.

6. While an event such as a new customer joining or a customer exiting may also result in an adjustment to a customer’s connection charges, we have not shown adjustments to connection charges in this explanatory guide, given that adjustments to the connection charges follow the methodology in the existing TPM and that methodology remains the same in the proposed TPM.

7. In our worked example, each event occurs in a successive pricing year. However, to see the effect on transmission charges for all customers, we need to view the changes from the next pricing year. This is because in the “event pricing year”, the only party that has an adjustment to its transmission charges is the party causing the event. All other customers will have their transmission charges adjusted from the start of the succeeding pricing year (assuming that this pricing year is not an “exempt pricing year”, clause 3, proposed TPM).

8. All capitalised terms that are not defined in this paper are as defined in the proposed TPM drafting (**proposed TPM**).

2 Worked Example

9. Please see below the customer map for the Worked Example

10. The key assumptions within the Worked Example are:

10.1 There are three regions: North, Middle and South (N, M and S).

10.2 There are six customers evenly split between Generation and Load: Load 1, Load 2 and Load 3 are load customers, and Gen 1, Gen 2 and Gen 3 are generators.

10.3 There are five connection locations: 1 to 5. Customers Load 3 and Gen 3 share connection assets at connection location 5.

10.4 There is one high-value post-2019 BBI (**Post 2019-BBI**) across all three regions, with each region benefiting in part from this Post-2019 BBI.

10.5 There is one pre-2019 A BBI across all three regions (**Appendix A BBI**), with each customer benefiting in part from this Appendix A BBI.

3 Preliminary allocations

11. The four types of transmission charges through which Transpower will recover its recoverable revenue in any Pricing Year:

11.1 connection charges (not analysed in the worked example);

11.2 benefit-based charges (Post-2019 BBI), calculated using the price-quantity method;

11.3 benefit-based charges (Appendix A BBI); and

11.4 residual charges.

12. A summary of the allocation of benefit-based charges, BBI customer allocations (**CA**) and residual charges (where applicable) across all customers as of the commencement of pricing year 2023 is set out below:

Cr	Region	Connection Location	BBC: Post-2019 BBI CA (%) (see para 14)	BBC: Appendix A BBI CA (%) (see para 15)	% of residual revenue (see para 16)
Load 1	N	1	10	15	25
Gen 1	N	2	15	25	-
Load 2	M	3	20	10	50
Gen 2	S	4	8	20	-
Load 3	S	5	15	10	25
Gen 3	S	5	32	20	-
Total			**100%**	**100%**	**100%**

13. We set out in paragraphs 14 to 16 below further detail as to how Transpower has calculated the initial allocations set out in the preceding summary table.

14. **Benefit-Based Charges (Post-2019 BBI)**

14.1 There are three regions within our map: North; Middle; South.

14.2 Across the entire map, there is a single Post-2019 BBI.

14.3 The Post-2019 BBI:

14.3.1 is an electricity market BBI;

14.3.2 is a non-peak BBI;

14.3.3 is a high-value BBI; and

14.3.4 was commissioned in January 2022 with an asset life of 40 years.

Consequently, we will be using the price-quantity method to calculate the NPB for this BBI.

14.4 Each customer is in a maximum of one regional customer group (**RCG**) with respect to the Post-2019 BBI. These are:

14.4.1 Load 1 – regional demand group, region N

14.4.2 Gen 1 – regional supply group, region N;

14.4.3 Load 2 – regional demand group, region M;

14.4.4 Gen 2 and Gen 3 – regional supply group, region S;

14.4.5 Load 3 – regional demand group, region S.

14.5 The initial allocation of regional NPB to each regional customer group and each customer's BBI customer allocation for the Post-2019 BBI is set out below:

Cr	RCG	Regional NPB	Intra-regional allocation	Individual NPB	BBI CA (Post-2019) (%)
Load 1	N – demand	100	1	100	10%
Gen 1	N – supply	150	1	150	15%
Load 2	M – demand	200	1	200	20%
Gen 2	S – supply	400	0.2	80	8%
Gen 3			0.8	320	32%
Load 3	S – demand	150	1	150	15%
Total		**1,000**		**1,000**	**100%**

14.6 The intra-regional allocation has been calculated for each regional customer group by dividing the customer's intra-regional allocator for the regional customer group by the total of the values of all customer's intra-regional allocators for the relevant regional customer group (this is not technically a calculation set out in in the proposed TPM).

14.7 Relevant provisions, proposed TPM are as follows:

Definitions of "benefit-based charges", "BBI", "BBI customer allocation (limb (b))", "individual NPB", "intra-regional allocator", "high-value", "post-2019 BBI", "price-quantity method", "regional customer group", "regional demand group", "regional NPB" and "regional supply group" in clause 3, proposed TPM, and clauses 36, 43 to 53 and 63 to 64, proposed TPM.

15. **Benefit-Based Charges (Appendix A BBI)**

15.1 For the "Appendix A BBI" we assume the following allocations:

Cr	BBI CA (Appendix A) (%)
Load 1	15%
Gen 1	25%
Load 2	10%
Gen 2	20%
Load 3	10%
Gen 3	20%
Total	**100%**

15.2 Relevant provisions, proposed TPM are as follows:

Definitions of "Appendix A BBI", "BBI", "BBI customer allocation (limb (a))" and "pre-2019 BBI" in clause 3, proposed TPM, and clauses 36 and 42, proposed TPM.

16. **Residual Charges**

16.1 The initial allocations of AMDR for each load customer and each customer's percentage allocation of residual revenue is shown below:

Load Customer	AMDR	% of residual revenue
Load 1	150	25%
Load 2	300	50%
Load 3	150	25%
Total	**600**	**100%**

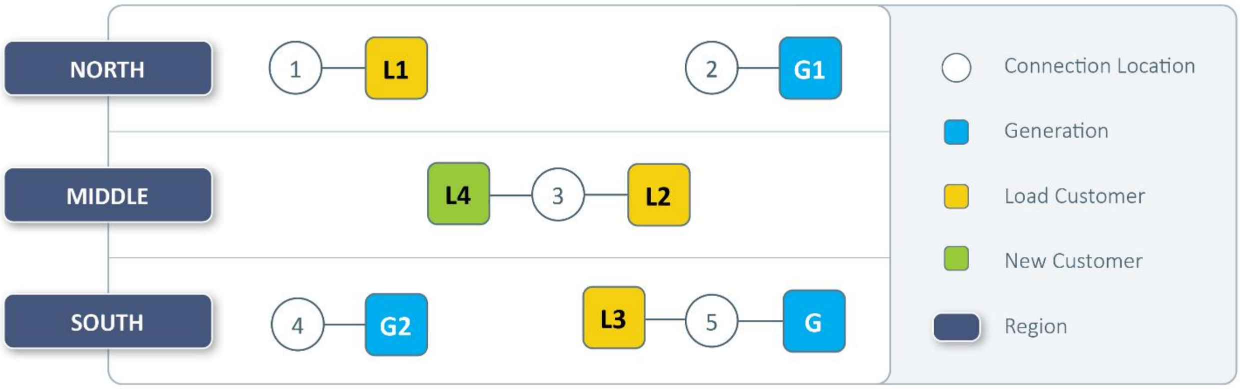
16.2 Relevant provisions, proposed TPM are as follows:

"AMDR", "residual charge", "residual charge adjustment factor" of clause 3, proposed TPM, and clauses 65 to 71, proposed TPM.

4 New load customer joining

17. We are now in pricing year 2023.

18. We assume a new load customer (Load 4) connects in region M at connection location 3:



19. Load 4's connection at connection location 3 in region M is:

    19.1 a connection charge adjustment event (clause 73(a), proposed TPM) (not analysed in the Worked Example);

    19.2 a benefit-based charge adjustment event with respect to the Post-2019 BBI, as Load 4 will benefit from the Post-2019 BBI (clauses 78(1)(b) and 80(2)(a), proposed TPM);

    19.3 a benefit-based charge adjustment event with respect to the Appendix A BBI (clauses 78(1)(b) and 80(2)(b), proposed TPM); and

    19.4 a residual charge adjustment event (clause 90(1)(a), proposed TPM).

20. This Worked Example demonstrates the impact of Load 4's connection on:

    20.1 benefit-based charges payable for the Post-2019 BBI;

    20.2 benefit-based charges payable for the Appendix A BBI; and

    20.3 residual charges (for load customers only).

21. **Benefit-based charge adjustment event (clause 80, proposed TPM) – Post-2019 BBI**

    21.1 The Post-2019 BBI is a high-value, electricity market BBI. Accordingly, the price-quantity method will be used to calculate each customer's benefit-based charges for the Post-2019 BBI.

    21.2 Transpower will undertake the following steps to calculate each customer's BBI customer allocation for the Post-2019 BBI after the connection of Load 4:

    (A) Identify each regional customer group in which Load 4 is a beneficiary:

    21.3 Load 4, as a load customer connected in region M, is a member of the "regional demand group" in region M in respect of the Post-2019 BBI. ("Regional demand group" in clause 3, proposed TPM, and clause 80(2)(a), proposed TPM).

(B) Calculate Load 4's BBI customer allocation in respect of the Post-2019 BBI:

21.4 To calculate Load 4's BBI customer allocation, Transpower will:

21.4.1 estimate Load 4's intra-regional allocator in respect of the regional demand group in region M, assuming Load 4's assets are fully operational (clauses 63(1) and 80(3)(a), proposed TPM);

21.4.2 calculate Load 4's individual NPB ($) for the Post-2019 BBI (clause 80(3)(b) of the proposed TPM) using the following formula (clause 48, proposed TPM) (but as per clause 80(3)(b)(ii), proposed TPM, Load 4's intra-regional allocator is excluded from the denominator in this formula):

$$NPB = \sum_{g} \left(PVRNPB_g \times \frac{IRA_g}{\sum IRA_{g\ total}} \right)$$

where

$PVRNPB_g$ is the present value of **regional NPB** for **regional customer group** g, where **regional customer group** g is a **regional customer group** for the **BBI**—

(a) that has a positive present value of **regional NPB**; and

(b) of which the **customer** is a member

IRA_g is the value of the **customer's intra-regional allocator** for **regional customer group** g

$IRA_{g\ total}$ is the total of the values of all **customer's intra-regional allocators** for **regional customer group** g <u>(but excluding new customer's intra-regional allocator)</u>

21.4.3 calculate Load 4's BBI customer allocation (**CA**) for the Post-2019 BBI (clause 80(3)(c) and clauses 43(1) and 43(2) of proposed TPM) using the following formula (clause 43(1) of proposed TPM) (but as per clause 80(3)(c), proposed TPM, Load 4's individual NPB is excluded from the denominator in this formula):

$$CA = \frac{NPB}{NPB_{total}}$$

Where

NPB is the **customer's individual NPB** for the **post-2019 BBI**

NPB_{total} is the total of all **customer's individual NPBs** for the **post-2019 BBI** <u>(but excluding new customer's individual NPB)</u>

(C) Calculate scale factor and scale-down all beneficiaries' BBI customer allocations:

21.5 A scale factor (F) to be applied to the BBI customer allocations for all customers that are beneficiaries of the Post-2019 BBI is calculated by Transpower, using the following formula (clause 80(3)(d), proposed TPM):

$$F = \frac{1}{1 + CA}$$

where CA is the new **customer's BBI customer allocation** for the **post-2019 BBI** calculated under sub-section (B) above

21.6 Once calculated, each customer's BBI customer allocation is scaled down using the scale factor, including for Load 4 (clause 80(3)(d), proposed TPM).

(D) Add Load 4's individual NPB to regional NPB for Load 4's regional customer group for Post-2019 BBI:

21.7 Transpower adds the individual NPB for Load 4 to the regional NPB of Load 4's regional customer group for the Post-2019 BBI, being regional demand group M (clause 80(3)(e), proposed TPM).

22. The table below shows the changes to each customer's BBI customer allocation for the Post-2019 BBI (pre and post the arrival of Load 4):

Cr	Individual NPB (pre-L4 connection)	BBI CA (Post-2019) (%) (pre-L4 connection)	Individual NPB (post-L4 connection)	BBI CA (Post-2019) (%) (post-L4 connection)
Load 1	100	10%	100	9%
Gen 1	150	15%	150	14%
Load 2	200	20%	200	18%
Gen 2	80	8%	80	7%
Load 3	150	15%	150	14%
Gen 3	320	32%	320	29%
Load 4	0	-	100	9%
Total	**1,000**	**100%**	**1,100**	**100%**

23. **Benefit-based charge adjustment event (clause 80, proposed TPM) – Appendix A BBI**

23.1 As a customer connecting to the grid, Load 4 will be a beneficiary of the Appendix A BBI (clause 80(2)(b), proposed TPM).

23.2 Transpower will undertake the following steps to calculate each customer's BBI customer allocation for the Appendix A BBI after the connection of Load 4:

(A) Calculate Load 4's BBI customer allocation for Appendix A BBI:

23.3 To calculate Load 4's BBI customer allocation for the Appendix A BBI, Transpower will use the following formula (clause 80(6)(a), proposed TPM).

$$CA = E \times \frac{1}{J} \sum_j BF_j$$

where

E is **Transpower's** estimate of the new **customer's** average annual **offtake** or **injection** at the new **customer's connection location** when the new **customer's assets** are fully operational

J is the number of incumbent **customers** of the same type as the new **customer** (**generator** or **connected asset owner**)—

(a) at the new **customer's connection location**; or

(b) if there are no such incumbent **customers** at the new **customer's connection location**, at the **connection location** electrically closest to the new **customer's connection location** at which there is 1 or more such incumbent **customers**, as determined by **Transpower**,

each such incumbent **customer** being **customer** j

BF_j is **customer** j's **benefit factor** for the **Appendix A BBI**; and

23.4 The inputs to this formula that are required to be calculated are:

23.4.1 *Load 4's offtake*: Estimate of Load 4's average annual offtake at Load 4's connection location.

23.4.2 *Benefit factor*: Calculate "benefit factor" for each "incumbent customer" of the same type as Load 4 (e.g. connected asset owner at connection location 3) in relation to Appendix A BBI (see formula at clause 4, proposed TPM).

23.5 We have assumed for the purposes of the Worked Example that L2 is an "incumbent customer" of the same type as L4.

(B) Calculate scale factor and scale-down all beneficiaries' BBI customer allocations for the Appendix A BBI:

23.6 A scale factor (F) to be applied to the BBI customer allocations for all customers that are beneficiaries of the Appendix A BBI is calculated by Transpower using the following formula (clause 80(6)(b), proposed TPM):

$$F = \frac{1}{1 + CA}$$

where CA is the new **customer's BBI customer allocation** for the **Appendix A BBI** calculated under sub-section (D) above

23.7 Once calculated, each customer's BBI customer allocation is scaled down using the scale factor, including for Load 4 (clause 80(6)(b), proposed TPM).

24. The table below shows the changes to each customer's BBI customer allocation for the Appendix A BBI (pre and post the arrival of Load 4):

Cr	BBI CA (Appendix A) (%) (pre-L4 connection)	BBI CA (Appendix A) (%) (post-L4 connection)
Load 1	15%	14%
Gen 1	25%	24%
Load 2	10%	10%
Gen 2	20%	19%
Load 3	10%	10%
Gen 3	20%	19%
Load 4	-	5%
Total	**100%**	**100%**

25. **Residual charge adjustment event (clause 91, proposed TPM)**

25.1 Load 4 is a load customer and consequently will be obliged to pay a residual charge. Load 4's arrival triggers a residual charge adjustment event (clause 90(1)(a), proposed TPM).

25.2 Transpower will:

25.2.1 estimate Load 4's AMDR baseline as if Load 4 was a "recent load customer" assuming full operation of Load 4's assets (clauses 91(2)(a) and 91(5), proposed TPM). This will include Transpower taking into account the type and capacity of Load 4's assets and the AMDR baselines for any other load customers with assets of the same or similar type;

25.2.2 calculate all load customer's residual charges for the event pricing year to account of the new load customer's AMDR (clause 91(2)(b), proposed TPM and clauses 65 and 71, proposed TPM) (but not any change in residual revenue that may have occurred during the pricing year).

25.3 This will include Transpower:

25.3.1 Calculating the applicable "residual charge rate", in accordance with the following formula (clause 71, proposed TPM):

$$RCR = \frac{RR}{\sum AMDR_{total}}$$

where

RR is **residual revenue** for the **pricing year**

$AMDR_{total}$ is the total of all **customers' AMDR** for the **pricing year**.

25.3.2 Multiplying each load customer's AMDR by the residual charge rate.

25.4 Transpower must start Load 4's monthly residual charges calculated above as soon as reasonably practicable (clause 91(3), proposed TPM).

25.5 For the purposes of the Worked Example, we have calculated the percentage of residual revenue that will be allocated to each load customer by dividing each load customer's AMDR by the total AMDR of all load customers (this is not technically a calculation in the proposed TPM).

25.6 The table below illustrates each customer's percentage of residual revenue (pre and post the arrival of Load 4):

Load Customer	AMDR (pre-L4 connection)	Initial % of residual revenue (pre-L4 connection)	AMDR (post-L4 connection)	% of residual revenue (post-L4 connection)
Load 1	150	25%	150	18.75%
Load 2	300	50%	300	37.5%
Load 3	150	25%	150	18.75%
Load 4	-	-	200	25%
Total	**600**	**100%**	**800**	**100%**

26. **Summary Table**

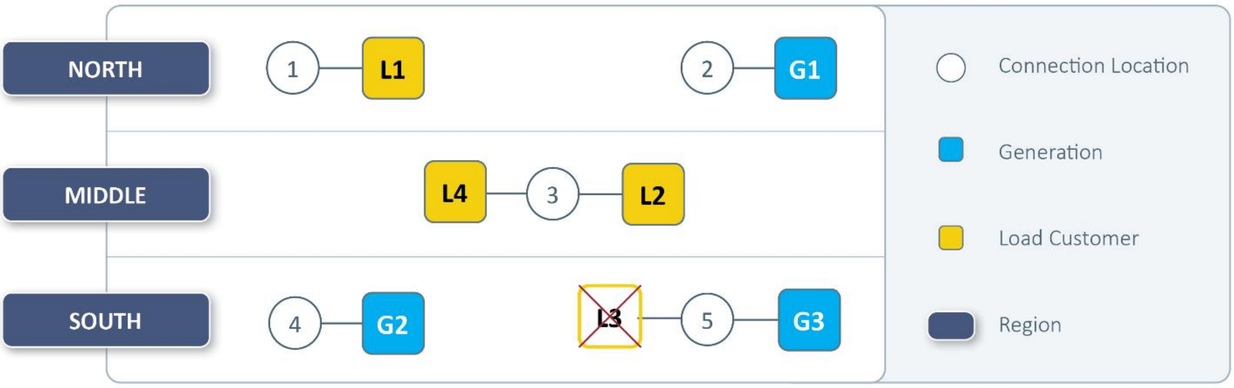
The summary table below shows changes to each customer's transmission charges following the arrival of Load 4:

Cr	BBC: Post-2019 BBI CA (%) (pre- L4 connection)	BBC: Post-2019 BBI CA (%) (post-L4 connection)	BBC: Appendix A BBI CA (%) (pre-L4 connection)	BBC: Appendix A BBI CA (%) (post-L4 connection)	% of residual revenue (pre-L4 connection)	% of residual revenue (post-L4 connection)
Load 1	10%	9%	15%	14%	25%	19%
Gen 1	15%	14%	25%	24%	-	
Load 2	20%	18%	10%	10%	50%	38%
Gen 2	8%	7%	20%	19%	-	
Load 3	15%	14%	10%	10%	25%	19%
Gen 3	32%	29%	20%	19%	-	
Load 4	-	9%	-	5%		25%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

5 Existing grid-connected customer exits completely

27. The Worked Example is now in pricing year 2024.

28. We assume that Load 3 exits as a customer entirely:



29. Load 3's disconnection from connection location 5 and exit as a customer is:

    29.1 a connection charge adjustment event (clause 73(1)(b), proposed TPM) (not analysed in the Worked Example);

    29.2 a benefit-based charge adjustment event with respect to the Post-2019 BBI and the Appendix A BBI (clause 78(1)(c), proposed TPM); and

    29.3 a residual charge adjustment event (clause 90(1)(b), proposed TPM).

30. This Worked Example demonstrates the impact of Load 3's exit as a customer on:

    30.1 benefit-based charges payable for the Post-2019 BBI. The impact on benefit-based charges for the Appendix A BBI would be similar, but is not demonstrated; and

    30.2 residual charges (for load customers only).

31. **Benefit-based charge adjustment event (clause 81, proposed TPM) – Post-2019 BBI**

    31.1 Load 3 was a beneficiary of the Post-2019 BBI immediately before ceasing to be a customer (clause 81(2), proposed TPM).

    31.2 Transpower will undertake the following steps to calculate each customer's BBI customer allocations for the Post-2019 BBI following Load 3's exit:

    (A) Revise exiting customer's BBI customer allocation:

    31.3 Transpower must make Load 3's BBI customer allocation 0 for the Post-2019 BBI, as the exiting customer (clause 81(3)(a)(i), proposed TPM).

    (B) Calculate scale factor and scale-up all remaining beneficiaries' BBI customer allocations:

    31.4 A scale factor (**F**) is calculated to be applied to the BBI customer allocations of all remaining beneficiaries of the Post-2019 BBI is calculated by Transpower using the following formula (clause 81(3)(a)(ii), proposed TPM):

$$F = \frac{1}{1 - CA}$$

where CA is the exiting **customer's BBI customer allocation** for the relevant **BBI** immediately before it was set to 0 under paragraph 31.2.

31.5 Once calculated, each remaining customer's BBI customer allocation is scaled-up using the scale factor (clause 81(3)(a)(ii), proposed TPM)

(C) Subtract Load 3's individual NPB from regional NPB for Load 3's regional customer groups

31.6 For each post-2019 BBI, Transpower will then subtract the exiting customer's individual NPB for the relevant BBI from the regional NPB of the regional customer group that the customer is a member of. For Load 3, this is regional demand group S. (Clause 81(3)(a)(iii), proposed TPM).

32. The table below shows the changes to each customer's BBI customer allocation for the Post-2019 BBI (pre and post exit of Load 3):

Cr	Individual NPB (pre-L3 exit)	BBI CA (Post-2019) (%) (pre-L3 exit)	Individual NPB (post-L3 exit)	BBI CA (Post-2019) (%) (post- L3 exit)
Load 1	100	9.1%	100	11%
Gen 1	150	13.6%	150	16%
Load 2	200	18.2%	200	21%
Gen 2	80	7.3%	80	8%
Load 3	150	13.6%	0	0%
Gen 3	320	29.1%	320	34%
Load 4	100	9.1%	100	11%
Total	**1,100**	**100%**	**950**	**100%**

33. **Residual charge adjustment event (clause 92, proposed TPM)**

33.1 Load 3 is a load customer and consequently its exit as a customer will trigger a residual charge adjustment event (clause 90(1)(b), proposed TPM).

33.2 Transpower will:

33.2.1 make Load 3's AMDR and residual charge 0, as the existing customer (clause 92(2)(a), proposed TPM); and

33.2.2 for the next pricing year, then Transpower would recalculate each customer's percentage share of the residual revenue and residual charge (clauses 65 to 71, proposed TPM).

33.3 The table below illustrates each customer's percentage of residual revenue (pre and post disconnection of Load 3):

Load Customer	AMDR (pre-L3 exit)	% of residual revenue (pre-L3 exit)	AMDR (post- Load 3 exit)	% of residual revenue (post-L3 exit)
Load 1	150	18.75%	150	23.08%
Load 2	300	37.5%	300	46.15%
Load 3	150	18.75%	0	0%

Load 4	200	25%	200	30.77%
Total	**800**	**100%**	**650**	**100%**

34. **Summary Table**

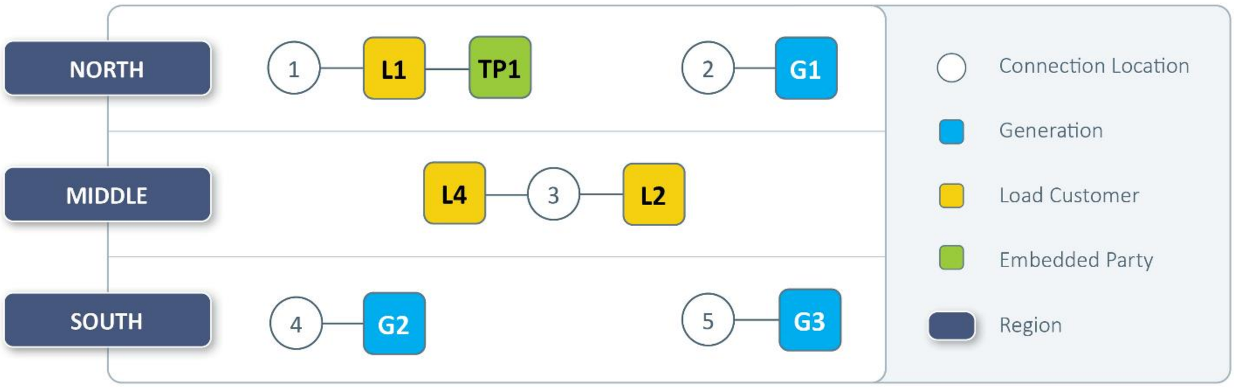
Please see a summary table showing changes to each customer's benefit-based charges for the Post-2019 BBI and residual charges following the exit of Load 3:

Cr	BBI CA (Post-2019) (%) (pre-L3 exit)	BBI CA (Post-2019) (%) (post-L3 exit)	% of residual revenue (pre-L3 exit)	% of residual revenue (post-L3 exit)
Load 1	9.1%	10.5%	18.75%	23.08%
Gen 1	13.6%	15.8%	-	-
Load 2	18.2%	21.1%	37.5%	46.15%
Gen 2	7.3%	8.4%	-	-
Load 3	13.6%	0%	18.75%	0%
Gen 3	29.1%	33.7%	-	-
Load 4	9.1%	10.5%	25%	30.77%
Total	**100%**	**100%**	**100%**	**100%**

6 Large embedded plant connects to host customer's local network

35. The Worked Example is now in pricing year 2025.

36. We assume Third-Party 1 connects large embedded generating plant to Load 1's (a distributor's) local network:



37. The connection of Third-Party 1's large embedded plant to Load 1's local network (**Large Plant Connection Event**) is a benefit-based charge adjustment event (clauses 78(1)(e) and 82, proposed TPM). It is not:

37.1 a "new customer" benefit-based charge adjustment event because, following the Large Plant Connection Event, Third Party 1 is not directly connected to the grid (and therefore not a Transpower customer). Accordingly, Third Party 1 will not incur transmission charges directly;

37.2 a connection charge adjustment event; or

37.3 a residual charge adjustment event.

38. Load 1 is the "host customer" for Third Party 1's embedded plant ("host customer', clause 3, proposed TPM). Load 1 is also the "connecting customer" for the embedded plant (clause 78(1)(e), proposed TPM).

39. This Worked Example demonstrates the impact of the Large Plant Connection Event on the benefit-based charges payable for the Post-2019 BBI. The impact on benefit-based charges for the Appendix A BBI would be similar but is not demonstrated.

40. Transpower will undertake the following steps to calculate each customer's benefit-based charges for the Post-2019 BBI after the Large Plant Connection Event:

(A) Pretend a notional generator connected at connection location 1

40.1 Transpower pretends a notional new generator (**Notional Customer**) has connected plant that is equivalent to Third-Party 1's embedded plant directly to the grid at the relevant connection location (clause 82(2)(a), proposed TPM), and then undertakes a "new customer" benefit-based charge adjustment event calculation for the Notional Customer (clause 80, proposed TPM).

40.2 In the Worked Example, the relevant connection location is connection location 1, being the connection location electrically closest to Third-Party 1's point of connection to Load 1's network (clause 82(2)(a)(ii), proposed TPM).

40.3 The Notional Customer is therefore a member of regional supply group N for the post-2019 BBI.

(B) Calculate Notional Customer's BBI customer allocation in respect of Post-2019 BBI

40.4 As described in Part 4, Transpower:

40.4.1 estimates the value of the Notional Customer's intra-regional allocator for regional supply group N, being mean historical annual injection (clause 80(3)(a), proposed TPM);

40.4.2 calculates the Notional Customer's individual NPB for the Post-2019 BBI (clause 80(3)(b), proposed TPM);

40.4.3 calculates the Notional Customer's BBI customer allocation for the Post-2019 BBI (clause 80(3)(c), proposed TPM);

40.4.4 calculates the scale factor for the BBI allocations for the Post-2019 BBI, and scales down the BBI customer allocations, including for the Notional Customer (clause 80(3)(d), proposed TPM).

(C) Allocate Notional Customer's BBI customer allocation and benefit-based charge for Post-2019 BBI to Load 1

40.5 Transpower attributes the Notional Customer's BBI customer allocation, individual NPB and benefit-based charge for the Post-2019 BBI to Load 1, as the "connecting customer", by way of increase to Load 1's BBI customer allocation, individual NPB and benefit-based charge for the Post-2019 BBI (clause 82(2)(b), proposed TPM).

40.6 Transpower adds the Notional Customer's individual NPB to the regional NPB of Load 1's regional customer group for the Post-2019 BBI, being regional demand group N (clauses 82(4)(a) and 80(3)(e), proposed TPM).

41. **Summary table**

41.1 The table below shows the changes for the Post-2019 BBI assuming the existence of the Notional Customer (pre and post the Large Plant Connection Event):

Cr	Individual NPB (pre-Large Plant Connection Event)	Individual NPB (post-Large Plant Connection Event)	BBI CA (Post-2019) (%) (pre-Large Plant Connection Event)	BBI CA (Post-2019) (%) (post-Large Plant Connection Event)
Load 1	100	100	10.5%	10%
Gen 1	150	150	15.8%	15%
Load 2	200	200	21.1%	20%
Gen 2	80	80	8.4%	8%
Gen 3	320	320	33.7%	32%
Load 4	100	100	10.5%	10%
NC	-	50	-	5%
Total	**950**	**1000**	**100%**	**100%**

41.2 The table below shows the changes for the Post-2019 BBI once the Notional Customer's individual NPB and BBI customer allocation is attributed to Load 1 (pre and post the Large Plant Connection Event:

Cr	Individual NPB (pre- Large Plant Connection Event)	Individual NPB ($) (post-Large Plant Connection Event)	BBI CA (Post-2019) (%) (pre- Large Plant Connection Event)	BBI CA (Post-2019) (%) (post-Large Plant Connection Event)
Load 1	100	150	10.5%	15%
Gen 1	150	150	15.8%	15%
Load 2	200	200	21.1%	20%
Gen 2	80	80	8.4%	8%
Gen 3	320	320	33.7%	32%
Load 4	100	100	10.5%	10%
Total	**950**	**1000**	**100%**	**100%**

7 Existing customer disconnects from a connection location (but remains connected at another connection location)

42. The Worked Example is now in pricing year 2026. The pricing year is less than 10 years after the date that the Post-2019 BBI was commissioned (being January 2022).

43. For the purposes of this Worked Example, we have presented a different customer map, with the following new set of assumptions:

    43.1 there are six connection locations, rather than five as in the previous Worked Example;

    43.2 Gen 1 is connected at two connection locations: connection location 2 and connection location 6;

    43.3 Gen 1, as an injection customer connected at connection location 6:

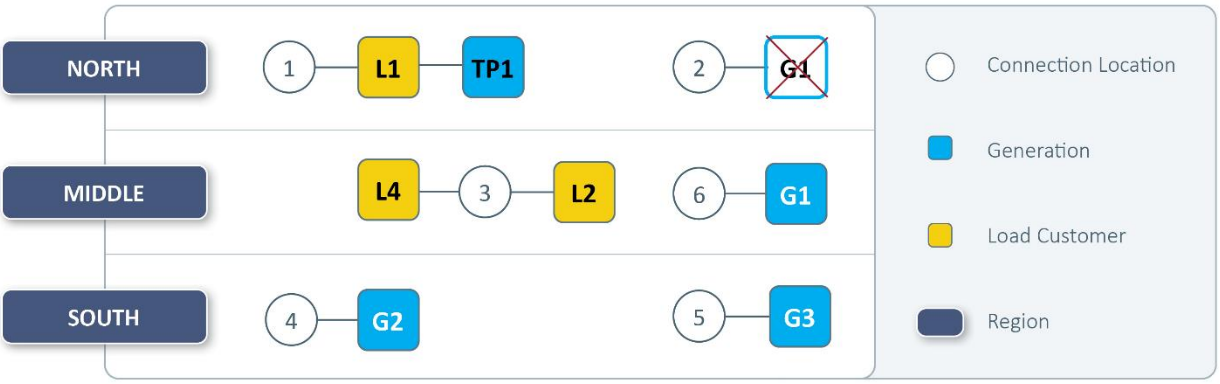
        43.3.1 is not a beneficiary of the Post-2019 BBI;

        43.3.2 is a beneficiary of the Appendix A BBI.

44. For the purposes of this Worked Example:

    44.1 Gen 1 disconnects from connection location 2 and ceases to be a beneficiary of the Post-2019 BBI; and

    44.2 Gen 1 remains connected at connection location 6 and continues to be a beneficiary of the Appendix A BBI



45. This event:

    45.1 will trigger a benefit-based charge adjustment event in respect of the Post -2019 BBI (clause 78(1)(d) and 82, proposed TPM); and

    45.2 will trigger a connection charge adjustment event in respect of connection location 2 (clause 73(b), proposed TPM) (not analysed in the Worked Example).

46. This Worked Example demonstrates the impact on Gen 1's benefit-based charges after Gen 1's disconnection from connection location 2 (and therefore ceasing to be a beneficiary from the Post-2019 BBI) while remaining connected at connection location 6 (and therefore continuing to be a beneficiary of the Appendix A BBI).

47. Transpower will undertake the following steps to calculate the changes to Gen 1's benefit-based charges after Gen 1's disconnection from connection location 2:

(A) Pretend a notional generator disconnected from connection location 2

47.1 Transpower pretends a notional generator (**Notional Customer**) has disconnected a large plant that is equivalent to Gen 1's large plant from connection location 2 and exits as a customer (clause 82(3)(a)(i) of proposed TPM) and then undertakes an exiting customer calculation for this Notional Customer (clause 81, proposed TPM).

47.2 The Notional Customer will exit as a member of regional supply group N for the Post-2019 BBI.

47.3 As described in Part 5, Transpower makes the Notional Customer's BBI customer allocation and benefit-based charges 0 for the Post-2019 BBI (clause 81(3)(a)(i), proposed TPM).

(B) Identify whether relevant post-2019 BBI is a "continuing" BBI and calculate Gen 1 BBI customer allocation

47.4 The Post-2019 BBI was commissioned more recently than 10 years before the date that Gen 1's large plant was disconnected, and consequently, the Post-2019 BBI is a continuing BBI (clause 82(5), proposed TPM).

47.5 As the Post-2019 BBI is a "continuing BBI" and Gen 1 will continue to be a customer (connected at connection location 6) after the disconnection of its large plant from connection location 2, then until the start of the pricing year commencing on April 2032 (being the first pricing year that starts at least 10 years after the Post-2019 BBI's commissioning date, i.e. until end of PY2032 (clause 82(6), proposed TPM):

47.5.1 there is no scaling-up of each other customer's BBI customer allocation for the Post-2019 BBI (clause 82(7)(a), proposed TPM); and

47.5.2 the Notional Customer's BBI customer allocations (and benefit-based charges) for the Post-2019 BBI are attributed to Gen 1 as if it remained a customer in respect of the Post-2019 BBI (clause 82(7)(b), proposed TPM), in addition to the benefit-based charges that Gen 1 would be obliged to pay as a beneficiary of the Appendix A BBI.

47.6 On and from the pricing year commencing on April 2032:

47.6.1 Gen 1 will no longer be obliged to continue to pay a benefits-based charge in respect of the Post-2019 BBI (clause 82(6), proposed TPM); and

47.6.2 each other customer of the Post-2019 BBI will have its BBI customer allocations scaled in accordance with clause 81(3)(a)(ii), proposed TPM.

48. **Summary table**

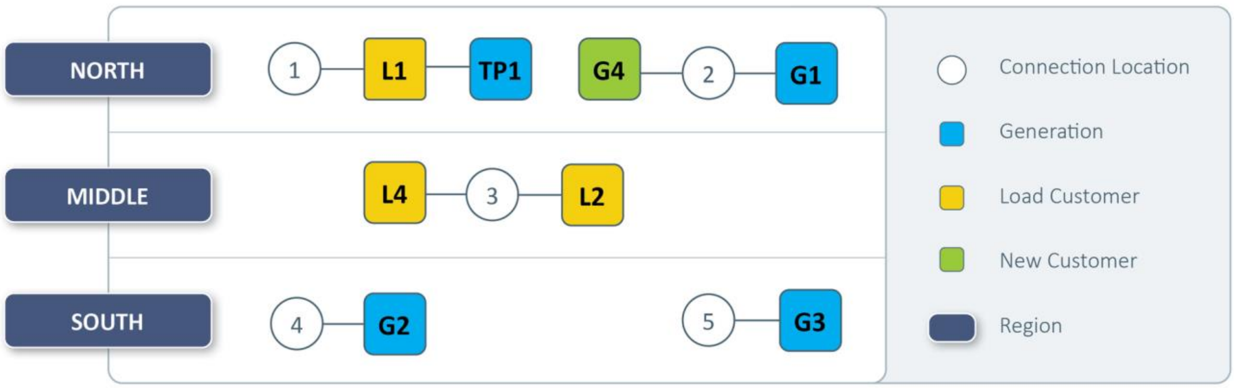
The table below shows the changes assuming the existence of the Notional Customer, allocating the Notional Customer's BBI customer allocation to Gen 1 for the continuing BBI (up to 2032) and post-2032 (pre and post disconnection of Gen 1's large plant from connection location 2):

Cr	RCG	BBI CA (Post-2019) (%) (pre-G1 disconnection)	BBI CA (Post-2019) (%) (post-G1 disconnection) (assuming Notional Customer)	BBI CA (Post-2019) (%) (post-G1 disconnection) (without Notional Customer)	BBI CA (post-2019) (%) (post-G1 disconnection) (post-2032)
Load 1	N - demand	15%	15%	15%	18%
Gen 1	N - supply	15%	-	15%	0%
Load 2	M - demand	20.0%	20.0%	20.0%	24%
Gen 2	S – supply	8.0%	8.0%	8.0%	9%
Gen 3	S – supply	32.0%	32.0%	32.0%	38%
Load 4	M - demand	10.0%	10.0%	10.0%	12%
NC	N - supply	-	15%	-	-
Total		**100%**	**100%**	**100%**	**100%**

8 Substantial and sustained change in grid use (SSCGU)

49. For the purposes of the Worked Example, we now assume that a substantial sustained change in grid use (**SSCGU**) occurs.

50. The SSCGU occurs due to a new generator (Gen 4) connecting a large plant at connection location 2. Gen 4's connection of a large plant at connection location 2 produces an expected total annual injection of at least 5% of average total annual injection and Transpower reasonably expects the change to persist for at least 5 years after the transmission charges are adjusted in response to this change. This constitutes a substantial and sustained change in grid use or SSCGU ("substantial sustained change in grid use or SSCGU" in clause 3, proposed TPM and clause 8, proposed TPM).



51. The occurrence of a SSCGU:

    51.1 triggers a benefit-based charge adjustment event in respect of the Post-2019 BBI (clause 78(1)(m), proposed TPM); and

51.2 does not trigger a benefit-based charge adjustment in respect of the Appendix A BBI. Instead, this would trigger a new customer connection or customer exit benefit-based charge adjustment event (as applicable), with the consequent pro-rata reallocation of the benefit-based charges for the Appendix A BBI.

52. Transpower will undertake the following steps to calculate each customer's benefit-based charges in respect of the Post-2019 BBI after the SSCGU:

(A) Identifying affected post-2019 BBIs

53. Transpower must determine any post-2019 BBIs that satisfy the following three conditions (clause 89(2)(a), proposed TPM):

53.1 *The post-2019 BBI is expected to be "high-value" at the start of the SSCGU's pricing year (clause 89(2)(a)(i), proposed TPM):* A BBI is "high-value" if the depreciated value of the BBI at the relevant time exceeds the base capex threshold in the Transpower Capex IM ("high-value", clause 3, proposed TPM). As of today's date, the base capex threshold is $20,000,000.

53.2 *Determine whether the distribution of regional NPB for the post-2019 BBI is likely to have changed materially as a result of the SSCGU, compared to the distribution of regional NPB or the post-2019 BBI immediately before the SSCGU (clause 89(2)(a)(ii), proposed TPM).*

53.3 *The SSCGU was not a market scenario used to calculate the existing BBI customer allocations for the post-2019 BBI (clause 89(2)(a)(iii), proposed TPM)*: If Transpower has already taken the relevant event into account in calculating the existing BBI customer allocations, then the occurrence of this event does not trigger a "SSCGU" requiring a full recalculation of all regional and individual NPBs, and BBI customer allocations.

54. We assume that the SSCGU results in each of the three conditions being satisfied for the Post-2019 BBI. If a SSCGU occurred but it did not trigger all three relevant criteria for a given post-2019 BBI, then the occurrence of the event (whether a connection or disconnection) would be treated as new customer connection or customer exit benefit-based charge adjustment event (as applicable).

(B) Recalculate each beneficiaries' BBI customer allocations (clause 89(2)(b), proposed TPM)

55. For the Post-2019 BBI, Transpower will then re-calculate each beneficiary's BBI customer allocations in full as if the relevant BBI were a new high-value post-2019 BBI (clause 89(2)(b), proposed TPM). This is a full recalculation of regional NPBs, together with all beneficiaries' BBI customer allocations and benefit-based charges for the relevant post-2019 BBI.

56. Transpower:

56.1 will use a standard method to recalculate beneficiaries' BBI customer allocations, although it does not need to be the same standard method as was used to calculate the existing BBI customer allocations for the relevant BBI (clause 89(3)(a), proposed TPM);

56.2 may use different factual, counterfactual, investment grids, system limits, scenarios, modelled regions and regional customer groups used to calculate the existing BBI customer allocations for the relevant BBI (clause 89(3)(b), proposed TPM).

57. The recalculated regional NPBs, BBI customer allocations and benefit-based charges will be payable from the SSCGU's "start pricing year", with the first pricing year starting at least 6 months after the SSCGU.

9 Stand alone cost prudent discount (SACPD)

58. The Worked Example is now in pricing year 2027.

59. We now assume that Load 2 is granted a SACPD for all of its transmission charges.

60. Chapter 13: Part I – Prudent Discount Policy of the Decisions and Reasons Paper explains the basis on which a SACPD will be granted.

61. In order for a SACPD to be granted, the "alternative project" that is the subject of the SACPD application must bypass all transmission services for the relevant customer (limb (b) of the definition of "alternative project, clause 3, proposed TPM). Consequently, if a prudent discount is granted, the benefit-based charges of the recipient of the prudent discount (**Recipient Customer**) during the term of the prudent discount agreement are 0 (clause 134, proposed TPM).

62. This Worked Example demonstrates how Transpower recovers a prudent discount granted to Load 2 as the Recipient Customer.

63. **Prudent discounts**

64. When Transpower grants a prudent discount and enters into a prudent discount agreement with the Recipient Customer, Transpower will calculate the following amounts:

64.1 amount of prudent discount that is granted to the Recipient Customer;

64.2 the annuity, which continues to be payable by the Recipient Customer to Transpower in accordance with the terms of the relevant prudent discount agreement (clauses 119 and 120, proposed TPM); and

64.3 Recipient Customer's benefit-based charges, which will be 0 (clause 134, proposed TPM). Importantly, the Recipient Customer's BBI customer allocation for each BBI will not be scaled down to 0, only the benefit-based charges.

65. There are two separate types of "prudent discount recovery charges" through which Transpower will recover a prudent discount that is granted to a Recipient Customer:

65.1 BBI prudent discount recovery charges (clause 3 and clause 135(1), proposed TPM), from other beneficiaries of the relevant "discounted BBIs"; and

65.2 (for IBPDs only) residual prudent discount recovery charges (clause 3 and clause 135(2), proposed TPM), from other load customers.

66. The purpose of the BBI prudent discount recovery charges and (if applicable) the residual prudent discount recovery charges is to recover from customers (other than the Recipient Customer) the amount of the prudent discount, net of any annuity payable by the Recipient Customer.

67. In our Worked Example, Load 2 is granted a SACPD, then all of the "net" prudent discount is recovered through BBI prudent discount recovery charge (**BPDS**), and no residual prudent discount recover charges (**RPDS**) are chargeable. The methodology for calculating each customer's BPDS is set out below:

68. **BBI prudent discount recovery charges (clause 135(1), proposed TPM)**

(A) Formula for calculating BBI prudent discount recovery charges

68.1 The first step is for Transpower to identify the BBIs of which the Recipient Customer was a beneficiary, defined as the "discounted BBIs".

68.2 In our Worked Example, the Post-2019 BBI and the Appendix A BBI are discounted BBIs.

68.3 Each customer that is a beneficiary of a discounted BBI will incur a BBI prudent discount recovery charge.

68.4 The formula for calculating the BPDS for an individual customer (that is not the Recipient Customer) for a given discounted BBI is as follows (clause 135(1), proposed TPM):

$$BPDS_{cb} = (PD - A) \times \frac{BBC_{recipient\ b}}{\sum_k BBC_{recipient\ k} + RC_{recipient}} \times \frac{BBC_{cb}}{\sum_j BBC_{jb}}$$

where

PD	is the amount of the relevant **prudent discount** for the **pricing year**
A	is the annuity payable by the **prudent discount recipient** for the **prudent discount** and **pricing year**
$BBC_{recipient\ b}$	is the **prudent discount recipient's benefit-based charge** for **discounted BBI** b and the **pricing year** without the **prudent discount**
$BBC_{recipient\ k}$	is the **prudent discount recipient's benefit-based charge** for **discounted BBI** k for the **pricing year** without the **prudent discount**, where **discounted BBI** k is a **discounted BBI** for the **prudent discount** (including **discounted BBI** b)
$RC_{recipient}$	is:

(a) if the **prudent discount** includes any discount to the **prudent discount recipient's residual charge** or **connection charges**, the **prudent discount recipient's residual charge** for the **pricing year** without the **prudent discount**; or

(b) otherwise, 0.

BBC_{cb} is **customer** c's **benefit-based charge** for **discounted BBI** b and the **pricing year**

BBC_{jb} is **customer** j's **benefit-based charge** for **discounted BBI** b and the **pricing year**, where **customer** j is a **beneficiary** of **discounted BBI** b and not the **prudent discount recipient** (including **customer** c).

(B) Applying to Worked Example

68.5 For the purposes of the Worked Example, we assume the following for pricing year 2027:

68.5.1 Post-2019 BBI: covered cost = $1,000,000

68.5.2 Appendix A BBI: covered cost = $500,000

68.6 The table below set out a hypothetical set of BBI customer allocations and residual revenue percentages for each customer immediately prior to the SACPD being granted to Load 2:

Cr	BBI CA (post-2019) (%)	Post-2019 BBC ($): (Assuming covered cost of $1,000,000)	BBI CA (Appendix A) (%)	Appendix A BBC ($): (Assuming covered cost of $500,000)
Load 1	15.0%	150,000	22.6%	112,903
Gen 1	15.0%	150,000	24.2%	120,968
Load 2	20.0%	200,000	9.7%	48,387
Gen 2	8.0%	80,000	19.4%	96,774
Gen 3	32.0%	320,000	19.4%	96,774
Load 4	10.0%	100,000	4.8%	24,194
Total	**100%**	**$1,000,000**	**100%**	**$500,000**

68.7 Load 2 is beneficiary of the Post-2019 BBI and the Appendix A BBI. Therefore, its benefit-based charges for both of the Post-2019 BBI and Appendix A BBI will be 0 (clause 134, proposed TPM drafting). Note that Load 2 will continue to pay connection charges and a residual charge, with no discount arising out of the granting of the SACPD.

68.8 Each beneficiary of the Post-2019 BBI and Appendix A will incur a BBI prudent discount recovery charge.

68.9 For the purposes of the Worked Example:

68.9.1 the "gross" prudent discount granted to Load 2 is $248,387, equal to the recipient customer's benefit-based charges immediately prior to the prudent discount being granted; and

68.9.2 the annuity payable by Load 2 to Transpower is $10,000.

68.10 The Worked Example Spreadsheet includes a calculation of each customer's BBI prudent discount recovery charge for the Post-2019 BBI and the Appendix A BBI.

68.11 This information is set out in the table below:

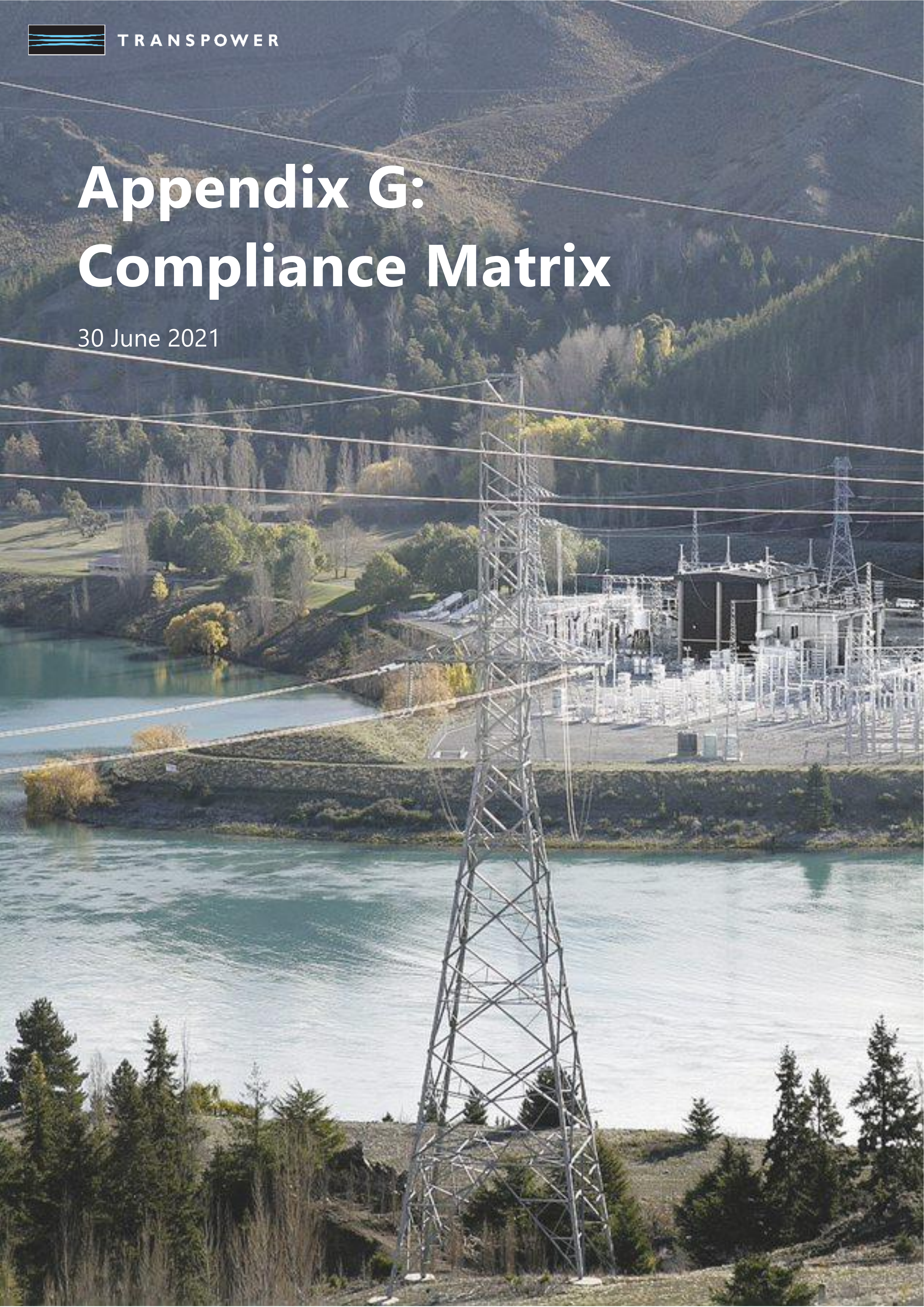
Cr	BBI CA (post-2019) (%)	Post-2019 BBC ($): (Assuming covered cost of $1,000,000)	BPDS: Post-2019 BBI ($)	BBI CA (Appendix A) (%)	Appendix A BBC ($): (Assuming covered cost of $500,000)	BPDS: Appendix A BBI ($)
Load 1	15.0%	150,000	35,990	22.6%	112,903	11,610
Gen 1	15.0%	150,000	35,990	24.2%	120,968	12,439
Load 2	20.0%	-	-	9.7%	-	-
Gen 2	8.0%	80,000	19,195	19.4%	96,774	9,951
Gen 3	32.0%	320,000	76,779	19.4%	96,774	9,951
Load 4	10.0%	100,000	23,994	4.8%	24,194	2,488
Total	**100%**	**$800,000**	**$191,948**	**100%**	**$451,613**	**$46,439**

68.12 As the prudent discount is a SACPD, then all of the “net” prudent discount is recovered through BPDS, and no RPDS are chargeable.

TRANSPOWER

Appendix G: Compliance Matrix

30 June 2021



This table provides a high-level roadmap of how our proposed TPM meets the requirements of the Guidelines. It is not an exhaustive summary and should be read together with the TPM drafting and accompanying reasons paper chapters.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		General/ preliminary	
1.	*In developing the **TPM** in accordance with these **Guidelines**, Transpower must, as far as reasonably practicable, use the following principles, including in selecting between options which otherwise comply with these **Guidelines*** *(specific clauses omitted)*	The Guidelines principles have formed a key part of our decision-making framework for developing the proposed TPM. In selecting between available options, we have used those principles to guide our decisions.	See generally Chapter 2 of the Reasons Paper. Specific detail in relation to how we applied these principles to particular components is provided in the detailed chapters of the Reasons Paper.
2.	*The **TPM** may differ in its details from the particular requirements in these **Guidelines** (but not their intent, including as set out in the Authority's intent section of these **Guidelines**), if Transpower considers, in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with these **Guidelines** in their entirety. For the avoidance of doubt, neither this clause (nor any other clause) limits the Authority's powers under clause 12.91 of the **Code**, including the power to refer back to Transpower a proposed **TPM** which it considers does not best meet its statutory objective and subsequently to amend a proposed **TPM**, nor its ability to interpret the **Guidelines** or its statutory objective in exercising those powers.*	The proposal contains some clause 2 departures, reflecting areas where we formed a view that departing from a specific requirement of the Guidelines would better meet the Authority's statutory objective than not doing so. See summary list included in Appendix A of the proposal.	See also Chapter 2 of the Reasons Paper. A more fulsome overview of each departure and reasons, is provided in the relevant Reasons Paper chapters.
3.	*All subsequent provisions in these **Guidelines** are to be interpreted and applied subject to clauses 1 and 2 above.*	This requirement has informed our approach.	Not applicable
4.	*Transpower must prepare a summary of Transpower's reasons for proposing the particular methods it has*	The Reasons Paper comprises specific chapters that summarise and explain the reasons for our proposals in relation to each component of the proposed TPM.	See Reasons Paper, and Appendix A

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	*included in the **TPM**, and provide it to the Authority along with the **TPM**. This summary must include details of:* *a. where, under clause 2, Transpower proposes a **TPM** which differs in its details from the particular requirements of these **Guidelines**, how the **TPM** differs from these **Guidelines** and Transpower's reasons for proposing a **TPM** which differs from these **Guidelines**, including why it considers that its proposed **TPM** better meets the Authority's statutory objective than complying with these **Guidelines** in their entirety; and* *b. where Transpower has made material assumptions in developing the **TPM**, the assumptions made and Transpower's reasons for making those assumptions.*	A summary of our proposed "clause 2 departures" is included in Appendix A of the proposal, and further discussion provided in the relevant Reasons Paper chapters. Any material assumptions that have informed our proposal are set out in the relevant Reasons Paper chapters.	
5.	*The **TPM** must include requirements for Transpower to consult on:* *a. the proposed **connection charge** for each **connection investment**;* *b. the proposed **benefit-based charge** and its allocation between designated transmission customers for each proposed **high-value benefit-based investment**;* *c. the proposed allocation of the **residual charge**;* *d. any transitional **congestion charge**;* *e. any kvar charge; and* *f. any proposed material changes to those charges (other than the total **residual charge**) or their allocations (in which case consultation must extend to whether and on what basis such changes are warranted under these **Guidelines**),*	This requirement is addressed in clause 17 of the proposed TPM. This provides that Transpower must consult with, as a minimum, the specified customer groups in clause 17(1), before finalising the relevant charges (or adjustments to those charges). Consultation may occur as part of Transpower or the Commission's consultation under the Capex IM, other parts of the Code, or transmission agreements (clause 17(3).	See clause 17 See also section 5 of Chapter 3 the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	with parties who have a material financial interest in the respective 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 charges** 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** or, where applicable, as a result of a prudent discount. Information provided for the purposes of this clause should be sufficient to enable the designated transmission customer to understand the basis for Transpower's calculations of its **transmission charges**.*	This requirement is addressed in clause 18 of the proposed TPM. Our proposal is to use the existing notification mechanism under transmission agreements to provide customers with this information. For load customers, the proposed TPM requires this information to include the amount of unallocated opex and reassignment amounts included in residual revenue (and therefore subject to the residual charge) (see clause 18(a)-(b)). We propose to recover prudent discounts by way of separate prudent discount recovery charges.	See clause 18 See also section 6 of Chapter 3 the Reasons Paper.
7.	*The **TPM** must provide that, where it is necessary to consider the characteristics of, benefits or costs accruing to, incentives on, or other matters related to a designated transmission customer under the **TPM**, that assessment must also consider the characteristics of, benefits or costs accruing to, incentives on, or other matters related to any party whose equipment is directly or indirectly electrically connected through that designated transmission customer's network to the grid.*	This principle is reflected across various aspects of the proposed TPM. For example: • In the context of BBCs, net private benefits for "host customers" is defined by reference to the sum of quantified benefits and disbenefits the owners of embedded plant connected to the host customer's local network or grid-connected plant are expected to receive from the relevant BBI (clause 3, definition of "NPB").	See clause 3, 5, 78(1)

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		• In the context of the residual charge, "load customer" is defined by reference to gross energy, which includes different types of electricity embedded behind a customer's point of connection to the grid (clause 3, 5). • In the context of adjustments, certain changes to embedded plant are BBC adjustment events (clause 78(1)).	
8.	*Where these **Guidelines** require allocations of charges based on expected **positive net private benefits**, the **TPM** must result in an allocation between <u>designated transmission customers</u> that is broadly in proportion to their expected **positive net private benefits**.*	This principle is reflected in a number of aspects of the proposed BBC allocation methods – see below. As a result, the proposed TPM in our view results in BBC customer allocations that are proportional to expected positive NPBs.	See generally Part D, clauses 36-64 See also Chapter 7 of the Reasons Paper
9.	*The **TPM** must provide for the treatment of a <u>transmission alternative</u> to be consistent with the treatment the type of **investment** (i.e. **connection investment** or **benefit-based investment**) which the <u>transmission alternative</u> seeks to avoid would have received under these **Guidelines** or, where this is not reasonably practicable, the cost of <u>transmission alternatives</u> must be allocated to the <u>designated transmission customers</u> that benefit from them in proportion to <u>Transpower's</u> reasonable assessment of the relative level of **positive net private benefit** that each customer receives from them.*	Transmission alternatives are addressed through the following aspects of the proposed TPM: • Definitions of "connection transmission alternative" and "interconnection transmission alternative" (clause 3). • For transmission alternatives in connection investments, see clause 26(4) of the proposed TPM. The operating cost of the transmission alternative for a pricing year is shared between customers at the relevant connection locations in proportion to their total connection charges at those locations. • For the costs of transmission alternatives in BBIs, see clause 41(1) of the proposed TPM. Transmission alternative opex is a type of recoverable cost under clause 3.1.3(c) of the Transpower IMs. These will form part of the covered cost of the relevant BBI as opex	See clauses 3, 26(4) and 41(1) See also section 7 of Chapter 3, and Chapter 6 of the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		attributed directly to the BBI – see Chapter 6 ("BBC Covered Cost") of the Reasons Paper.	
		Main component 1: connection charge	
11.	*The **TPM** must provide for the costs of connection investments to be recovered from those <u>designated transmission customers</u> whose <u>assets</u> are connected to the <u>assets</u> forming part of those **connection investments**.*	***General:*** Part C of the proposed TPM specifies how connection charges are calculated (clauses 26 – 35). Our approach to connection charges reflects moderate and incremental changes from the existing TPM. The methodologies for seeking recovery of costs associated with connection investments are similar to the existing TPM. ***FMD:*** The Part C regime also addresses first mover disadvantage (Type 2) by "socialising" the costs associated with provisioning additional capacity in connection investments among all customers paying the connection charge through the asset component. This proposal is a ***<u>clause 2 departure</u>*** from clause 11 of the Guidelines (see sections 10 and 12 of Chapter 5 ("Part C – Connection Charges") of the Reasons Paper). First mover disadvantage (Type 1) for connection investments is addressed through a new Funded Asset Component (FAC), which collects a financial contribution to the capital cost of the connection investment funded by the first mover from later customers, and rebating it back to the "first mover" customer. See clauses 28-29.	See generally Part C, clauses 26-35 See also Chapter 5 of the Reasons Paper See also Appendix A
12.	*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.*	The definition of "connection asset" includes "deep" connection assets as further described in clause 24(5)(b) of the proposed TPM.	See clauses 3, 24(5)(b) See also Chapter 4 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		Main component 2: benefit-based charge	
		BBCs must apply to BBIs	
13.	*The **TPM** must include a **benefit-based charge** for each **benefit-based investment**.*	Part D of the proposed TPM describes the methodologies that will be used to allocate the covered cost of BBIs among customers (clauses 36 – 64).	See generally Part D, clauses 36 - 64 See also Chapters 6 and 7 of the Reasons Paper.
14.	*A **benefit-based investment** means:* a. *any **post-2019 investment** in the **interconnected grid**;* b. *the following **pre-2019 investments** in the **interconnected grid**:* (i) *the Bunnythorpe-Haywards Reconductoring Project;* (ii) ***investments** in and associated with the <u>HVDC link</u>;* (iii) *the Lower South Island Renewables Project;* (iv) *the Lower South Island Reliability Project;* (v) *the North Island <u>Grid</u> Upgrade (NIGU) Project;* (vi) *the Upper North Island Dynamic Reactive Support Project; and* (vii) *the Wairakei Ring Project;* c. ***post-2019 upgrading expenditure** as provided for in clauses 25 to 26 below; and* d. ***pre-2019 investments** in the **interconnected grid** identified by means of a method established under clauses 62 and 63 below.*	The proposed TPM defines a BBI to mean an "Appendix A BBI" or a "post-2019 BBI". The Appendix A BBIs are consistent with those in clause 14(b) of the Guidelines. Post-2019 BBIs are defined as interconnection investments commissioned after 23 July 2019, consistent with the Guidelines. Post-2019 upgrading expenditure is treated as a new or existing BBI, under clause 38 of the proposed TPM. We have not proposed to incorporate Additional Component E into the proposed TPM, so clause 14(d) of the Guidelines is not captured in the relevant BBI definitions.	See clauses 3 and 38 See also Chapters 7 and 14 of the Reasons Paper.

<table>
<tr><th>Clause</th><th>Guidelines requirement</th><th>How the proposed TPM meets the requirement</th><th>Reference</th></tr>
<tr><td colspan="4">BBCs must recover the covered cost of BBIs</td></tr>
<tr><td>15.</td><td>Except as provided for in clause 16, 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 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 opex reasonably attributable to the benefit-based investment based on an allocation of the opex allowance for the pricing year as set in the IPP; and
d. any other costs attributable to that benefit-based investment.</td><td>General: Under the proposed TPM, covered cost will be calculated by reference to the return of capital (depreciation), a return on capital (capital charge), and opex and other costs reasonably attributable/attributable to the BBI. Each component is included in the formula at clause 40 of the proposed TPM.
Opex reasonably attributable to a BBI will be calculated using either direct attribution method, where it is practicable to do so, or a proxy method – see clause 41.</td><td>See clauses 40 and 41
See also Chapter 6 of the Reasons Paper.</td></tr>
<tr><td>16.</td><td>The benefit-based charge must recover the full present value of the covered cost of a benefit-based investment except where and to the extent that:</td><td>This requirement is addressed by recalculating the annual covered cost for a BBI each pricing year, as a means of evaluating "full present value". See clause 40(1) of the proposed TPM.</td><td>See clauses 22, 40, 77, 79, 88 and 94-96
See also Chapters 6, 7 and 10 of the Reasons Paper.</td></tr>
</table>

<table>
<tr><th>Clause</th><th>Guidelines requirement</th><th>How the proposed TPM meets the requirement</th><th>Reference</th></tr>
<tr><td></td><td>a. the annual benefit-based charges are adjusted or ended under clause 32 because the benefit-based investment is substantially damaged or destroyed;
b. that benefit-based investment is subject to reassignment in accordance with clauses 34 to 40;
c. the benefit-based charge has been scaled back in accordance with clauses 43 and 44; or
d. part of the covered cost is recovered through the connection charge as a consequence of the implementation of Additional Component A: adjustments to charges for staged commissioning.</td><td>The BBC is designed to recover the covered cost of a BBI in accordance with the Part D regime of the proposed TPM, unless one of the following exceptions occurs, consistent with the Guidelines:
• a “material damage” adjustment event has occurred (clause 79);
• all or part of the covered cost has been reassigned (clauses 95 and 96);
• the charge has been scaled back to reflect voluntary under-recovery (clauses 77, 88 and 94); or
• part of the cost has already been recovered through the connection charge because of staged commissioning (clause 22(4)) – see below.
In relation to staged commissioning, the possibility of an asset changing from interconnection to connection (and back again) does not create a risk of double recovery because the asset will be continually depreciating and cannot be an interconnection asset and connection asset at the same time.</td><td></td></tr>
<tr><td colspan="4" align="center">Recovery of covered cost of a BBI over time</td></tr>
<tr><td>17.</td><td>The TPM must provide that <u>Transpower’s</u> recovery of the capital components for each benefit-based investment for a pricing year under the TPM must be the same as the forecast depreciation and forecast return on capital in that pricing year for that benefit-based investment under the IPP.</td><td>Clause 40(1)-(3) of proposed TPM addresses capital component calculations for covered cost.
Capex components will be, for each asset comprised in the BBI, depreciation calculated in accordance with Transpower’s IMs (i.e. straight line) and a capital charge on the asset’s depreciated value (calculated using our regulated WACC).</td><td>See clause 40
See also Chapter 6 of the Reasons Paper.
See also Appendix A</td></tr>
</table>

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		The proposed calculation of annual covered cost will be by reference to depreciation and opening RAB values for the preceding financial year. This is a ***clause 2 departure*** from clause 17 of the Guidelines, which refers to forecasts.	
		Allocating annual BBCs among customers	
18.	*The **TPM** must include one or more standard methods for allocating **annual benefit-based charges**.*	***General:*** Part D of the proposed TPM sets out the proposed BBC allocation methods. Customers who are "beneficiaries" of the relevant BBI (defined as those customers who have a positive BBC customer allocation) pay BBCs (clause 36(1)). A beneficiary's BBC is calculated by multiplying the BBI's covered cost for the relevant pricing year by the beneficiary's "BBI customer allocation" (clause 36(2)). The approach to determining BBI customer allocations will depend on whether it's a pre-2019 BBI, or post-2019 BBI: • For pre-2019 investments, the BBC customer allocation is calculated based on the initial Schedule 1 allocations set out in the Guidelines (subject to any adjustments) (clause 42); and • For post-2019 investments, the BBC customer allocation reflects the customer's individual NPB for the BBI as a proportion to all other customers (clause 43(1)). A customer's individual NPB is calculated using a standard method, or simple method (clause 43(2)). ***Standard methods:*** Two standard methods are proposed to determine NPBs for post-2019 high value investments (>the base capex threshold, currently	See clauses 36, 42-56 See also Chapter 7 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		$20m), being the Price-Quantity Method (clauses 44-52), and Resiliency Method (clause 54-56): • *Price-Quantity Method*: This method quantifies electricity and/or ancillary service market benefits, reliability benefits and/or other benefits. Any post-2019 high value BBI which is not a "resiliency BBI" will be subject to this method. • *Resiliency Method*: A separate resiliency method will be used for a sub-set of BBIs which are primarily needed to mitigate a risk of cascade failure or high-impact low-probability events (defined as "resiliency BBIs" in the proposed TPM). The table at clause 43(2) of the proposed TPM outlines when each method will apply.	
19.	*The **TPM** may include one or more simple methods for allocating **annual benefit-based charges**.*	Clauses 57 – 62 of the proposed TPM relate to the simple method. The simple method is proposed for low value investments (<the base capex threshold, currently $20m), which is a regional allocation model. The regional definitions under the simple method use grid flow patterns to identify regions where beneficiaries are likely to be aligned.	See clauses 57-62 See section 16 of Chapter 7 of the Reasons Paper
20.	*The **TPM** must provide:* *a. that <u>Transpower</u> must use a standard method to allocate the **annual benefit-based charges** for **high-value post-2019 benefit-based investments**;*	A standard method will apply to "post-2019 BBIs" where they are expected to be "high value" when fully commissioned (defined by reference to the base capex threshold prescribed in the Transpower Capex IM, being currently $20m).	See clauses 3, 44-53 See sections 5-14 of Chapter 7 of the Reasons Paper
	*b. that <u>Transpower</u> must use Schedule 1 to allocate the **annual benefit-based charges** for the **benefit-based investments** included in Schedule 1; however, <u>Transpower</u> may adjust the*	The Schedule 1 investments set out in the Guidelines are replicated through the definition of "Appendix A BBIs" in the proposed TPM.	See clauses 3 and 42 See sections 5-14 of Chapter 7 of the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	allocations in Schedule 1 in accordance with clauses 31 to 44, including for the purposes of the initial allocation;	Under the proposed TPM: • the initial beneficiary customers for those investments are defined as those listed in Schedule 1 of the Guidelines; and • the initial allocations are based on those set out in Schedule 1 of the Guidelines, in each case adjusted as necessary, namely to account for changes to customers, or to apply any relevant adjustments (clauses 42(2)-(3)).	
	c. *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****; and*	The table at clause 43(2) of the proposed TPM shows the allocation method that will apply, depending on the type of BBI. The only remaining BBIs not captured by Guidelines clauses 20(a) and (b) above are post-2019 low-value BBIs. For those BBIs, the simple method will apply (clause 43(2)).	See clause 43 See sections 5-14 and 16 of Chapter 7 of the Reasons Paper
	d. *where these* ***Guidelines*** *provide for an adjustment to the allocations, a method or methods for making that adjustment. That method(s) must be a standard method, simple method or combination of both, but need not be the same as any other standard, simple or combined method provided for in these* ***Guidelines****.*	This requirement is addressed in Part F ("Adjustments") of the proposed TPM.	See Part F See Chapter 10 of the Reasons Paper
21.	*A standard method 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 the expected* ***positive net private benefit*** *to them from the* ***benefit-based investment*** *over its* ***remaining life****.*	***Allocates in proportion to benefits:*** Each of the standard methods calculates customers' positive net private benefits from the relevant high-value post-2019 BBI ("individual NPB"). The price-quantity method does this by first calculating "regional NPB" for a number of regional customer groups. The individual NPBs calculated under either standard method then determine the "BBI customer allocations" for the BBI,	See clauses 3, 44-56 See also sections 4-15 and 19 of Chapter 7 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		which, when multiplied by the BBI's covered cost, result in BBCs that are proportional to expected positive net private benefits. ***Remaining life****:* Benefits will be assessed over the remaining "useful life" of a BBI, or a 20 year period from the date of full commissioning, whichever is the shorter (see definition of "standard method calculation period", clause 3). This is a ***clause 2 departure***, see Chapter 7 ("Part D – BBC Allocation") of the Reasons Paper.	
22.	*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****;*	***Administrative simplicity:*** The simple method delivers administrative simplicity for participants, and is expected to be lower cost to implement (than the standard methods) across the suite of investments to which it applies. The simplicity is further promoted by calculating largely fixed individual NPBs and BBI customer allocations for 5-year "simple method periods".	See clauses 57-62 See also section 16 of Chapter 7 of the Reasons Paper.
	b. must, in Transpower's reasonable opinion, result in an allocation of the ***benefit-based charge*** *between the designated transmission customers who receive a major* ***positive net private benefit*** *from the* ***benefit-based investment*** *that is broadly in proportion to expected* ***positive net private benefits****; and*	***Allocates in proportion to benefits:*** The simple method calculates customers' positive net private benefits from the relevant low-value post-2019 BBI ("individual NPB"). The simple method does this by first calculating "regional NPB" for a number of regional customer groups, and in respect of investment regions, based on historical injection and offtake in, and electricity flows between, the regions. The individual NPBs calculated under the simple method then determine the "BBI customer allocations" for the BBI, which, when multiplied by the BBI's covered cost, result in BBCs that are proportional to expected positive net private benefits.	See clauses 57-62 See also section 16 of Chapter 7 the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		Weighting between load and generation: The simple method allows for a "demand adjustment factor" to be applied to the calculation of regional NPB (clauses 62(2) and (3)). The demand adjustment factor has an initial value of 1, resulting in a 50:50 split of regional NPB between generation and load. Transpower must review the demand adjustment factor for each 5-year "simple method period" and update as appropriate, taking into account allocation trends between load and generation under the standard method, with the objective of producing allocations that are broadly proportional to benefits (clause 62(3)).	
	c. *may exempt <u>designated transmission customers</u> 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**. Where a <u>designated transmission customer</u> is so exempted, the simple method must provide for the allocation they would have received to be recovered from those <u>designated transmission customers</u> who have received an allocation of the **annual benefit-based charges** for the **benefit-based investment**.*	No "exemption" mechanism is proposed/ required as part of the simple method.	Not applicable
23.	*The **TPM** must provide that, save for benefits and costs included at <u>Transpower's</u> discretion, the treatment of benefits and costs used to calculate **net private benefits**, for **post-2019 benefit-based investments** must be aligned with the treatment of the relevant **electricity market benefit** or **cost elements** under the **Transpower Capex IM** investment test applied to the **investment** (if any), except to the extent that <u>Transpower</u> reasonably*	The BBC methods are aligned with the treatment of the relevant electricity market benefit or cost elements under the Transpower Capex IM. Clause 43(3) of the proposed TPM also reflects this principle. This requires consistency, as far as reasonably practicable, with investment test assumptions and inputs, except as otherwise stated in the proposed TPM or to the extent this would not	See clause 43 See also Chapter 7 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	considers such alignment would not result in an allocation between designated transmission customers that is in proportion to their expected ***positive net private benefits****.*	produce allocations that are broadly proportional to NPB, reflecting the language in clause 23 of the Guidelines.	
24.	*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.*	BBC allocations are fixed over the life of the BBI and are not changed, unless for example an adjustment event occurs (clause 36).	See clause 36 See also Chapter 7 of the Reasons Paper
	Upgrading infrastructure		
25.	***Upgrading expenditure****, in relation to existing* ***benefit-based investments****, means expenditure that results in an extension to the existing* ***benefit-based investment's*** *expected* ***remaining life*** *or otherwise increases the benefits that* ***benefit-based investment*** *is expected to provide.*	The proposed TPM captures three types of investment in an existing grid asset or transmission alternative. Refurbishment investment and replacement investment have the definitions as set out in the Transpower Capex IM and also apply to a transmission alternative as if it was an investment in the grid.	See clause 3 See also section 5.2 of Chapter 10 of the Reasons Paper
26.	*The* ***TPM*** *must provide that, where Transpower undertakes* ***upgrading expenditure****, that* ***upgrading expenditure*** *must be recovered by either:* *a. treating the* ***upgrading expenditure*** *as a new* ***benefit-based investment****, in which case the* ***upgrading expenditure*** *must be recovered using a method prescribed in the* ***TPM*** *for recovering the* ***covered cost*** *of a* ***post-2019 benefit-based investment*** *having a capital cost equal to the cost of the* ***upgrading expenditure****; or* *b. treating the* ***upgrading expenditure*** *as part of the original* ***investment*** *to which the* ***upgrading expenditure*** *relates, in which case:*	This is addressed through clause 38 of the proposed TPM. This provides that, for a post-2019 BBI, refurbishment or replacement investments must be treated as: (a) part of the existing post-2019 BBI, in which case, the investment amount will be added to the covered cost but will not change the BBI customer allocations; (b) a separate post-2019 BBI; or (c) part of a separate post-2019 BBI referred to at (b) above. These must be treated as a separate post-2019 BBI if it will have different customers or a materially different distribution of NPB than the existing post-2019 BBI (clause 38(4)).	See clause 38 See also section 5.2 of Chapter 10 of the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	i. *the remaining* ***covered cost*** *of the overall* ***benefit-based investment*** *is to be calculated by combining the* ***covered cost*** *of the* ***upgrading expenditure*** *with the unrecovered* ***covered cost*** *of the original* ***investment****; and* ii. *the allocation of the* ***benefit-based charge*** *for the overall* ***investment*** *is to be calculated by combining the expected* ***net private benefits*** *resulting from the* ***upgrading expenditure*** *(determined using the method referred to in clause 26(a)) with the future* ***net private benefits*** *of the original* ***investment****, as originally calculated under clause 20 and subject to any adjustments made under clauses 31 to 44.*	Pre-2019 (Appendix A BBIs) – refurbishment or replacement investment must be treated as: (a) a separate post-2019 BBI; or (b) part of a separate post-2019 BBI referred to at (a) above (investment amount will be added to the covered cost for the BBI but will not change its customer allocations). Enhancement investment must be treated as a separate post-2019 BBI, per clause 38(3) of the proposed TPM.	
Main component 3: residual charge			
27.	*The* ***TPM*** *must provide for a residual charge to apply to all* <u>*designated transmission customers*</u>*, to the extent that they are load customers, to allow* <u>*Transpower*</u> *to recover any remaining* ***recoverable revenue*** *not recovered through other* ***transmission charges****.*	***General:*** Part E of the proposed TPM specifies how the residual charge will be applied to load customers (clauses 65 – 71). Clause 2(e) of the proposed TPM confirms the purpose of residual charges, being to recover the remainder of recoverable revenue not recovered through other TPM charges, consistent with the Guidelines. "Residual revenue" is defined as recoverable revenue for the pricing year less connection charges and BBCs (clause 3). The formula for applying residual charges to load customers is set out in clause 65(2) of the proposed TPM, and is consistent with the Guidelines. In summary, the annual residual charge is determined by multiplying the residual charge rate (**RCR**) by the	See clauses 2, 3, 65-71 See generally Chapter 8 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		load customer's anytime maximum demand (residual) (**AMDR**) for the relevant pricing year. A customer's AMDR is based on their base AMDR for pricing years 2014 – 2017 adjusted for changes in total gross energy (**TGE**). The RCR is calculated by dividing the residual revenue for that year by the sum of all customers' AMDR for that pricing year (clause 71).	
	Load customer *means a* *designated transmission customer* *whose equipment draws* *electricity* *from the* *grid* *or from any generation behind the* *designated transmission customer's* *point* *or* *points of connection* *(including* *distributed generation* *and behind-the-meter generation).*	The proposed TPM expands upon the definition of "load customer" in the Guidelines (see clauses 3 and 5). This will capture a customer who, at a connection location during a trading period, is or was 1 or more of the following: • An **offtake customer** – a customer who takes electricity from the grid; • A **supplied load customer** – a customer, connected to the grid, into whom electricity flowed from a generating plant; • A **supplying load customer** – a generator, connected to the grid, from which electricity flowed directly to a consuming plant. The inclusion of "supplying load customer" means the residual charge will apply to generators for any embedded load – this is a ***clause 2 departure***. As a result, under clauses 5(3) and (4) of the proposed TPM, a grid-connected generator's embedded load counts towards its "gross energy" and "maximum gross demand".	See clauses 3 and 5 See also section 5 and 7.1 of Chapter 8 of the Reasons Paper. See also Appendix A
28.	*The* ***TPM*** *must provide for the* ***residual charge*** *to be initially allocated in proportion to each* *designated transmission customer's* *historical anytime maximum* *demand**, which may be calculated using data supplied by the* *reconciliation manager**, and is to be calculated by:*	The initial (baseline) allocation of residual charges will be in proportion to load customers' gross historical anytime maximum demand (kW), averaged across four historic financial years (financial years 2014 to 2017), per clause 67(1) of the proposed TPM.	See clause 67 See also paragraph 19.1 of Chapter 8 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	a. *taking, in a year from 1 July to 30 June, the customer's anytime maximum demand for that year, which is calculated by:* i. *for each one of the customer's points of connection, taking the highest value in any trading period in that year of gross load, being the sum of:* 1. *the net quantity of electricity flow from the grid at that point of connection; and* 2. *Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection; and* 3. *aggregating each of those sums across all the customer's points of connection;* b. *taking the average of the customer's anytime maximum demand over the four years from 1 July 2014 to 30 June 2018.*	Two approaches are available to calculate the AMDR baseline, which is dependent on whether the customer is a pre-existing load customer or a recent load customer – see discussion of clause 33(c) of the Guidelines below. The formula at clause 67 addresses the average requirement by providing that the MGD is to be calculated for the 2014 to 2017 pricing years, then divided by 4.	
29.	*The* ***TPM*** *must provide that, in initially allocating the* ***residual charge*** *under clause 28, Transpower may adjust the allocation where necessary to accommodate circumstances in which, in Transpower's reasonable opinion, a designated transmission customer has experienced a substantial reduction in anytime maximum demand, due to factors that are largely beyond the customer's control or influence. For the purposes of this clause, a substantial reduction in demand is to be assessed relative to the designated transmission customer's remaining demand.*	This is addressed through clause 69 of the proposed TPM, and the proposed definition of "reduction event". This mechanism allows us to adjust a load customer's initial allocation if there has been a sustained reduction in the customer's maximum gross demand after the end of financial year 2017 due to any event or circumstance beyond the customer's control. "***Reduction event***": We propose to use a threshold of 10 MW for determining whether a reduction event has occurred, consistent with our proposed threshold for "large" in the proposed TPM.	See clauses 3, 67, 68 and 69 See also paragraph 19.2 of Chapter 8 of the Reasons Paper.
30.	*The* ***TPM*** *must provide that for each* ***pricing year****, from and including the* ***pricing year*** *commencing on 1 April*	The initial allocation of residual charges will be adjusted annually based on lagged gross annual	See clauses 66, 67 and 68

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	*2023, the **residual charge** is to be allocated in proportion to each <u>designated transmission customer's</u> adjusted historical anytime maximum <u>demand</u>, calculated as:* *$AHAMD_t = HAMD0 \times Ut / U0$* *where:* *$AHAMD_t$ is the <u>designated transmission customer's</u> adjusted historical anytime maximum <u>demand</u>.* *$HAMD_0$ is the <u>designated transmission customer's</u> historical anytime maximum <u>demand</u> calculated as described in clauses 28 and 29.* *U_t is the <u>designated transmission customer's</u> average total **gross** annual energy usage (measured in MWh) across the year commencing on 1 July four years and nine months prior to the start of the **pricing year** in which the adjustment applies and the three preceding years commencing on 1 July.* *U_0 is the <u>designated transmission customer's</u> average total **gross** annual energy usage (measured in MWh) across the four years from 1 July 2014 to 30 June 2018, reduced as necessary to be consistent with the reduction in anytime maximum <u>demand</u> under clause 29.*	energy usage (kWh) over the period of four financial years commencing eight years ago (clauses 66 and 68 of the proposed TPM). Clause 65 provides the starting formula for this, which provides that the annual residual charge is calculated by taking the AMDR and multiplying it by the residual charge rate. The formula for calculating the AMDR (the equivalent of $AHAMD_t$) is outlined in clauses 66 - 68 of the proposed TPM. The formula operates by taking the average MGD per customer from 2014 – 2017, and adjusting it by the proportion of the lagged average TGE as compared to the average TGE from 2014 – 2017.	See also paragraph 19.3 of Chapter 8 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	Adjustments to benefit-based charge and residual charge		
31 – 33	*Adjustments to benefit-based and residual charges* *(specific clauses omitted)*	See Guidelines mapping table and discussion in Chapter 10 ("Part F – Adjustments") in the Reasons Paper.	See generally Part F See also Chapter 10 of the Reasons Paper
	Reassignment		
34.	*The **TPM** must provide for a party to be able to make an application to <u>Transpower</u> for **reassignment** of **benefit-based charges**:*	Beneficiary customers and their embedded plant owners will be eligible to apply for reassignment of a BBI (proposed definition of "eligible person").	See clause 97-98. See also Chapter 11 of the Reasons Paper.
	*a. where that party has a material direct or indirect financial interest in the **annual benefit-based charge** for that **benefit-based investment**;*	We must reject an application if the applicant is not an "eligible person", defined as: • A beneficiary of the BBI to which the application relates, or • A person whose embedded plant is connected to the local network or grid connected plant of a beneficiary of the BBI. This in our view is a reasonable approach to defining "material direct or indirect financial interest" for the purposes of the Guidelines (see paragraph 22 of Chapter 11 ("Part G – Reassignment") of the Reasons Paper).	See clauses 3 and 99 See also section 5 of Chapter 11 of the Reasons Paper.
	*b. where the **benefit-based investment** has a current (depreciated) value of $5 million or more (with this threshold to be adjusted for inflation); and*	We must also reject an application if it does not relate to an "eligible BBI". An eligible BBI is defined as a BBI that satisfies certain conditions, including that the total closing RAB value of all grid assets for the BBI meets the "reassignment threshold".	See clauses 3, 97 and 99

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		Clause 97(2) sets the reassignment threshold at $5m for the first pricing year, adjusted for inflation for later pricing years. The proposed TPM defines closing RAB value using the definition in the Transpower IMs.	
	c. *whether or not the **benefit-based investment** has previously been subject to **reassignment**.*	The proposed TPM addresses this through the definition of "eligible BBI", which includes any relevant BBIs that are currently or were previously reassigned.	See clause 3
35.	*The **TPM** must provide that a **benefit-based investment** must, and may only, be subject to **reassignment** if, in <u>Transpower's</u> reasonable opinion, the circumstances which justify the **reassignment** are likely to be sustained and (over and above any changes which <u>Transpower</u> may take into account as a result of the application of clauses 31 to 33):*	This is reflected in clause 100(2), which provides that Transpower must approve the application if the circumstances justifying reassignment are "sustained" (defined in clause 8).	See clauses 8 and 100
	a. *for a **pre-2019 benefit-based investment**, the **investment's** value following **reassignment** would be less than 80% of its current value;*	The BBI must have a "BBI reassignment factor" of less than 0.8.	See clauses 100 and 101 See also section 7 of Chapter 11 of the Reasons Paper.
	b. *for a **post-2019 benefit-based investment**:* i. *where the disconnection from the <u>grid</u> of a single party, facility or plant 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.*	The proposed TPM adopts a similar approach for both pre-2019 and post-2019 BBIs. However, additionally the definition of eligible BBI provides that for a post-2019 BBI, the BBI will only be eligible, if one of the following apply: • at least 10 years have passed since the BBI's commissioning date ("stand-down period"); or • since the BBI's commissioning date either a beneficiary, or a beneficiary's plant, have permanently disconnected from the grid, and that disconnection caused the BBI's reassignment factor to be less than 0.8.	See clauses 3, 100 and 101 See also sections 6 and 7 of Chapter 11 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
36.	*The **TPM** must provide that, where Transpower receives an application for **reassignment** supported by evidence which Transpower in its reasonable opinion considers indicates that the conditions in clause 35 are likely to be met, it must undertake such investigations as it considers necessary for it to make an informed decision and then determine whether a **reassignment** is necessary under clause 35.*	The proposed TPM specifies the key procedures that will apply to reassignment applications, including application, assessment and decision-making criteria (see clauses 99-100). Some of the general requirements set out in clause 16 of the proposed TPM will also apply.	See clauses 16, 98, 99 and 100 See section 4 of Chapter 11 of the Reasons Paper
37.	*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.*	The proposed TPM contains a stand-down period of least 10 years to have passed since the commissioning date before a post-2019 BBI will be eligible for reassignment. The reasons for this are outlined in the Reasons Paper.	See clause 3, paragraph (b)(i) of the definition of "eligible BBI" See also section 6 of Chapter 11 of the Reasons Paper.
38.	*The **TPM** must provide that, where Transpower determines that the circumstances which led to the **reassignment** no longer exist and that the depreciated value of the **investment** is $5 million or more after adjusting for inflation, 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.*	Clause 106 of TPM addresses the criteria for reversing a reassignment. Clause 106(1)(c) contains the requirement that the BBI must meet the reassignment threshold. Clause 106(3) of the proposed TPM confirms that, if Transpower determines that the BBI's BBI reassignment factor is 0.8 or more, we must fully reverse the reassignment.	See clause 106 See also section 9 of Chapter 11 of the Reasons Paper.
39.	*The **TPM** must include a method for determining the value of a **benefit-based investment** following **reassignment** which is consistent with the change in forecast future demand for **transmission lines services** (over and above any changes taken into account as a*	Clause 96 sets out the formula to calculate the reassignment amount. This is calculated by multiplying the covered cost by (1 – the BBI's reassignment factor). Clause 95 provides that the eligible BBI's covered cost must be reduced by the amount calculated under clause 96.	See clauses 95 and 96 See section 8 of Chapter 11 of the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	*result of the application of clauses 31 to 33) which led to the **reassignment**, reversal or adjustment.*		
40.	*The **TPM** must provide that, where Transpower determines to carry out a **reassignment** with respect to a **benefit-based investment** or reverse or readjust the level of 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** (over and above any changes taken into account as a result of the application of clauses 31 to 33) which led to the **reassignment**, reversal or adjustment; and* c. *adjust the **residual charge** as necessary to take into account the changes to the **annual benefit-based charge**.*	***BBCs:*** Clause 95 of the proposed TPM contains the formula under which we must calculate the beneficiaries' BBC for the eligible BBI based on the reduction of its covered costs following reassignment (thus, treating this as a scaling adjustment). We propose not to automatically reallocate BBCs for a BBI when the BBI is reassigned. This is a ***clause 2 departure*** from clause 40(b) of the Guidelines. However, it is possible that reallocation events may also be triggered. ***Residual charge***: We do not consider that there needs to be a method to adjust residual charges as this will happen automatically through changes to residual revenue.	See clause 95 See also sections 8 and 10 of Chapter 11 of the Reasons Paper.
	Substantial and sustained change in grid use		
41.	*The **TPM** must:* a. *provide that Transpower may review the allocation of future **annual benefit-based charges** for a high-value **benefit-based investment** if, in Transpower's reasonable opinion, there has been, or it 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***	See Guidelines mapping table and discussion in Chapter 10 ("Part F – Adjustments") in the Reasons Paper.	See clauses 3, 78 and 89 See section 5.3 of Chapter 10 of the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	(which, in Transpower's reasonable opinion, has not been adequately accounted for by applying any of clauses 31 to 40 above as applicable) relative to the time the relevant charges were allocated; b. *provide that a substantial change in grid use will not have occurred:* i. *for a **post-2019 investment**, where the circumstances which have eventuated were factored into the calculations used to allocate the relevant charges (for example, where scenarios about future developments were used in the allocation); and* ii. *where there has not been a change in circumstances or event that caused a widespread, substantial change to the pattern of grid use relative to the use at the time the relevant charges were allocated;* c. *provide a method or methods for Transpower to determine whether there has been a substantial and sustained change in grid use affecting a **high-value benefit-based investment** (where the methods may differ for different kinds of **investment**); and* d. *provide that the method or methods referred to in clause 41(c) are such that the allocation review referred to in clause 41(a) is likely to be only rarely invoked.*		

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		Pro rata adjustments	
42.	*The **TPM** must ensure that where, as a result of an adjustment or adjustments under clauses 31 to 41 or otherwise, the percentage allocators used to allocate the **annual benefit-based charge** in respect of a **benefit-based investment** or the residual charge to individual <u>designated transmission customers</u> no longer total 100%, <u>Transpower</u> must adjust those allocators pro-rata so that the allocators total 100%.*	See Guidelines mapping table and discussion in Chapter 10 ("Part F – Adjustments") in the Reasons Paper.	See clauses 12, 80, 81, 89, 91 and 92 See section 5.3 of Chapter 10 of the Reasons Paper
		The charges may be scaled back	
43.	*The **TPM** must provide for the charges set under it to be scaled back if, in any **pricing year** <u>Transpower</u> wishes to recover less than its **recoverable revenue**.*	See Guidelines mapping table and discussion in Chapter 10 ("Part F – Adjustments") in the Reasons Paper.	See clauses 73, 77, 78, 88, 90 and 94 See Chapter 10 of the Reasons Paper
44.	*The **TPM** must provide that, where clause 43 applies, <u>Transpower</u> may 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 in the **residual charge**.*	See Guidelines mapping table and discussion in Chapter 10 ("Part F – Adjustments") in the Reasons Paper.	See clauses 73, 78 and 90 See Chapter 10 of the Reasons Paper
		Main component 4: prudent discount policy	
45.	*The **TPM** must provide for a prudent discount policy that encourages existing and prospective <u>designated transmission customers</u> not to inefficiently bypass the <u>grid</u>, including encouraging **load customers** not to inefficiently disconnect from the <u>grid</u> in favour of alternative supply.*	***General:*** Two types of prudent discount are available under the proposed TPM, consistent with the Guidelines: an inefficient bypass prudent discount (**IBPD**) which is similar to the existing discount available, and a new stand-alone cost prudent discount (**SACPD**).	See generally Part I (Prudent Discount Policy), and 124-129 in relation to the IBPD See also Chapter 13 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		This principle is addressed through the IBPD – see in particular clauses 124-129.	
46.	*The prudent discount **must** be available where a <u>designated transmission customer</u> can establish that:* *a. it would be technically and operationally feasible, and commercially beneficial, for the <u>designated transmission customer</u> to undertake the relevant action described in clause 45; and* *b. the relevant action would be inefficient to implement given <u>Transpower</u>'s economic costs of providing the <u>designated transmission customer</u> with access to the <u>grid</u> and the economic costs incurred by the <u>designated transmission customer</u> if it proceeded with the relevant action described in clause 45.*	This is reflected in clauses 124 – 129 of the proposed TPM, which specifically relate to the IBPD. Technical and operational feasibility criteria are set out in clause 126, and an efficiency test is set out in clause 127.	See clauses 124 – 129 See section 4 of Chapter 13 of the Reasons Paper
47.	*The **TPM** must further:* *a. include a method for determining the efficient standalone cost of the **transmission lines services** a <u>designated transmission customer</u> receives based on the hypothetical **investment** that would be required to supply solely that <u>designated transmission customer</u>;*	This requirement is reflected in clauses 130 – 134 of the proposed TPM, which specifically deal with SACPD. The method for assessing an efficient stand-alone investment is set out in section 132, which adopts a brownfields standard.	See clauses 130 – 134 See also section 5 of Chapter 13 of the Reasons Paper.
	b. ensure that the method provided for in clause 47(a) results in a standalone cost which, in <u>Transpower</u>'s reasonable opinion, approximates the cost of supplying transmission services that are of equivalent value to the customer, including in terms of access to energy, quality of energy supplied, reliability, security of supply, the cost of resource or other regulatory consents, and such other matters as <u>Transpower</u> considers relevant; and	Clause 131 sets out equivalence and other criteria applying to the alternative project, including commercial viability. The alternative must be shown to be commercially viable (but differs from an IBPD in that it does not need to be feasible to build from a consenting or property right perspective). In calculating stand-alone cost, an estimate for obtaining consenting or property rights are included based on the costs of obtaining equivalent rights if they were feasible (clause 131(2)).	See clauses 114 and 131 See also section 5 of Chapter 13 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		Clause 114(2) sets out the relevant matters which Transpower must consider in assessing whether an alternative project offers the same or a substantially similar level of service.	
	c. *provide that a prudent discount must be available where and to the extent that a <u>designated transmission customer</u>'s **transmission charges** exceed the standalone cost of the **transmission lines services** it receives.*	This requirement is reflected in clause 133, under which we must approve the application for a SACPD if the relevant criteria are satisfied. This includes the commercial viability criterion in clause 116, which in the case of a SACPD compares the cost of the alternative project (being an efficient stand-alone investment) with the customer's avoidable transmission charges (being the customer's BBCs in the case of a SACPD). If Transpower approves a customer's application for a prudent discount, we must promptly offer a prudent discount agreement to the customer (clause 119), which must provide for the SACPD recipient's BBCs to be 0 during the term of the agreement (clause 134).	See clause 116, 119, 133 and 134 See also section 5 of Chapter 13 of the Reasons Paper.
48.	*The **TPM** must detail practical ways to facilitate greater transparency on the matter of prudent discounts.*	The proposed TPM captures a number of practical methods designed to ensure transparency around prudent discounts. These include: • Publication of applications (clause 113(4)); • Consultation with customers on draft decisions to approve or reject applications (clause 117); • Independent review mechanism available to applicants (clause 118); • Publication of decision details, including supporting analysis, any conditions of approval, copies of the relevant prudent discount agreement (clause 121 and 122(2)); and	See clauses 113, 117, 118 121-123 See also section 6 and 7 of Chapter 13 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		• Publication of a prudent discount practice manual (clause 123), and consultation on key updates to it (clause 123(3)-(4)).	
		Transitional price cap	
49.	*Subject to clause 53, the **TPM** must provide for a cap on the sum (excluding GST) of each **existing load customer's**:* *a. **benefit-based charges** in respect of the **benefit-based investment**s included in Schedule 1;* *b. **residual charge**; and* *c. any surcharge imposed by the operation of clause 51.*	***General:*** The proposed TPM implements this requirement through clauses 108 – 110. These clauses specify how the transitional cap and cap recovery charges are calculated. The cap is applied by way of a "cap condition" (clause 108). A capped customer's transmission charges for each pricing year preceding 2038 are reduced to ensure the cap condition is satisfied.	See clauses 108 – 110 of the proposed TPM. See also Chapter 12 the Reasons Paper.
	***Existing load customer** means a load customer which, in Transpower's reasonable opinion, was fully operational prior to the beginning of the 2019/20 pricing year.* ***Load customer** means a designated transmission customer whose equipment draws electricity from the grid or from any generation behind the designated transmission customer's point or points of connection (including distributed generation and behind-the-meter generation).*	***Capped customers:*** The proposed TPM applies the cap to "capped customers", defined as: • for the first pricing year, a customer (other than a generator) who was a customer during pricing year 2019 and at least 2 pricing years prior – we propose this as a proxy for "fully operational" in the Guidelines; and • for each subsequent pricing year, any such customer who had a cap reduction for the previous pricing year. We do not propose to apply the cap to grid-connected generators for the reasons set out in the Reasons Paper.	See clauses 3, 108 See sections 5, 6 and 7 of Chapter 12 of the Reasons Paper.
50(a)	*Subject to clause 53, in setting a cap, the **TPM** must provide for:*	Clause 109 of the proposed TPM sets out the formula to calculate the difference cap applying to both distributors and direct consumers (but with an additional factor that applies to the later). Clause 108	See clauses 108-109 See also section 7.2 of Chapter 12 of the Reasons Paper.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	a. *the difference between a <u>distributor's</u> **transmission charges** subject to the cap as set out in clause 49, and 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 x (0.035 + CPI + L)* *where:* *B is the estimated total <u>electricity</u> bill for all <u>consumers</u> supplied, directly or indirectly, from the <u>distributor's</u> <u>network</u> in the 2019/20 **pricing year** (expressed in dollars, excluding <u>GST</u>), calculated as:* *B = C + P * V* *and where:* *CPI is the proportionate change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal);* *L is the proportionate increase in the <u>distributor's</u> load in MWh since the 2019/20 **pricing year**, if any (expressed as a decimal);* *C is the <u>distributor's</u> total line charge revenue for the 2019/20 **pricing year** excluding <u>GST</u> from the Schedule 8 Report on Billed Quantities and Line Charges Revenues of the Electricity Distribution Information Disclosure Determination 2012 (as amended from time to time);* *P is the volume weighted average of wholesale energy prices at the <u>distributor's</u>*	provides that the capped load customers capped charges (removing 2019 connection charges) must be equal to or less than the difference cap. At a high level, the difference cap for distributors says that the price increase for any given pricing year should be limited to 3.5% of the capped load customer's notional electricity bill for 2019. This is adjusted for inflation (CPI) and increases in total gross energy. In clause 109(2) and (5), neither the gross energy weighting for the variable P19 nor the capped load customer's total gross energy for the variable TGE19 needs to be obtained from the reconciliation manager. This proposal is a ***<u>clause 2 departure</u>*** from the requirements of clauses 50(a) and 50(b) of the Guidelines, as discussed in the Reasons Paper.	See also Appendix A

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	grid exit point or grid exit points for the 5 ***pricing 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 distributor's* ***gross*** *energy usage as determined by the reconciliation manager; and* *V* *is the distributor's total* ***gross*** *annual energy usage for the 2019/20* ***pricing year****, expressed in MWh, as determined by the reconciliation manager;*		
50(b)	*b. the difference between a direct consumer's* ***transmission charges*** *subject to the cap as set out in clause 49, and its* ***transmission charges*** *minus its* ***connection charges*** *in the 2019/20* ***pricing year****, to be limited to no more than:* *B x (0.035 + 0.02 x Y + CPI + L)* *where:* *B* *is the estimated total electricity bill of that direct consumer in the 2019/20* ***pricing year*** *(expressed in dollars, excluding GST), 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 start of the 2019/20* ***pricing year*** *minus 5;*	As above, this is also addressed through clause 109 of the proposed TPM, which covers both distributors and direct consumers in the one formula. We propose not to apply the cap to generators who are direct consumers, as a ***clause 2 departure***.	See clause 109 See also sections 5 and 7.1 of Chapter 12 of the Reasons Paper. See also Appendix A

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	CPI *is the proportionate change in the Consumer Price Index since the 2019/20* ***pricing year*** *(expressed as a decimal);* *L* *is the proportionate increase in the direct consumer's load in MWh since the 2019/20* ***pricing year****, if any (expressed as a decimal);* *T* *is the direct consumer's total* ***transmission charge*** *(including any* ***connection charge****) under the existing* ***TPM*** *in the 2019/20* ***pricing year****, excluding GST;* *P* *is the volume weighted average of wholesale energy prices at the distributor's grid exit point or grid exit points for the 5* ***pricing 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 distributor's* ***gross*** *energy usage as determined by the reconciliation manager; and* *V* *is the direct consumer's total* ***gross*** *annual energy usage in the 2019/20* ***pricing year*** *in MWh obtained from the reconciliation manager*		
50(c)	*c. the cap to be permanently removed:* *i. for a particular* ***existing load customer*** *if, in any* ***pricing year*** *after the* ***pricing***	This is addressed through the definition of "capped customer". Part (b) of this definition says that to be a capped load customer (and therefore receive the	See clauses 3, 108 See section 4 of Chapter 12 of the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	year *in which* ***benefit-based charges*** *are first applied to* ***low-value post-2019 benefit-based investment****s, the cap does not have the effect of reducing the* ***existing load customer's transmission charges*** *subject to the cap as set out in clause 49; and* *ii. in its entirety, by the end of the 2038/39* ***pricing year****.*	benefit of the cap), the customer must have received a cap reduction in the previous year. Under the proposed TPM at clause 108(1) confirms that the transitional cap applies to any pricing year preceding pricing year 2038.	
51.	*To the extent that the cap results in a reduction in* ***transmission charges*** *for one or more* ***existing load customers****, the revenue so forgone is to be recovered by a surcharge on and proportional to the total of the charges listed in clause 49 for each* <u>*designated transmission customer*</u>*.*	Clause 110 sets out a formula for a "cap recovery charge". The total cap reduction for a pricing year is recovered from customers in proportion to their total annual residual charges and BBCs for the BBIs in Schedule 1 of the Guidelines/ Appendix A of the proposed TPM. The cap recovery charge is not itself included in the "cap-recovery relevant charges" because otherwise the allocation formula would be circular.	See clause 110 and definition of "cap recovery charge" in clause 3 See section 4 of Chapter 12 of the Reasons Paper
52.	*For the avoidance of doubt, the surcharge on the* ***benefit-based charge*** *and the* ***residual charge*** *for a* <u>*designated transmission customer*</u> *is to be reduced if necessary and to the extent necessary to ensure that its* ***transmission charges*** *subject to the cap as set out in clause 49 meet the conditions in clause 50.*	Clause 108(1) provides that a capped load customer's transmission charges for each pricing year are to be reduced to ensure the cap condition is met. Transmission charges are defined as the connection charges, benefits based charges, cap recovery charge, prudent discount recovery charge and residual charges (clause 2).	See clauses 2, 108(1) See section 4 of Chapter 12 of the Reasons Paper
53.	*The cap provisions must not prevent* <u>*Transpower*</u> *from recovering its* ***recoverable revenue****.*	Clause 108(6) confirms that the cap condition must not result in Transpower recovering less than its recoverable revenue.	See clause 108(6) See section 4 of Chapter 12 of the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
Additional components			
54 – 68	*The* ***TPM*** *must incorporate each of* ***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*** *(specific clauses omitted)*	The proposed TPM adopts Additional Components A and B. It gives effect to the substantive requirements for Additional Components A and B (as set out in clauses 55 and 56 of the Guidelines) as follows: • (**Additional Component A – adjustments to charges for staged commissioning**) – Our proposal involves a hybrid asset classification whereby assets that would otherwise be connection assets are treated as interconnection assets for a limited time if they would ultimately be interconnection assets when fully commissioned. Clause 22(4) of the proposed TPM addresses this ("Identification of nodes and links as connection or interconnection"). • (**Additional Component B - charges for assets principally providing connection services**) – Our proposal is to make certain non-Transpower links "invisible" unless otherwise agreed, so that the existence of such links cannot impact on the connection/ interconnection status of grid assets. The proposed TPM implements this option in clauses 19(1) and 21(3) (through the definition of "grid assets").	See clauses 19(1), 21(3) and 22(4) See also Chapters 4 and 14 of the Reasons Paper

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
		Implementation	
66.	*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).*	See clause 37(1) of the proposed TPM, which provides that Transpower must start BBCs for a BBI from the BBI's "start pricing year". The proposed TPM defines the "start pricing year" for a BBI as the first pricing year that starts at least 6 months (or such shorter period as Transpower may determine is practicable) after the BBI's commissioning date, and which for Schedule 1 BBIs is the first pricing year (clause 3, definitions). The purpose of this approach is to ensure we can fit calculation and audit of, and consultation on, the BBCs within our normal annual pricing process, which can take up to six months to get through. This is technically a ***clause 2 departure*** from clause 66 of the Guidelines.	See clause 3 and 37(1) See also Appendix A
67.	*The **TPM** must provide that the implementation of the **benefit-based charge** for **low-value post-2019 benefit-based investments** and the **additional components**, other than a transitional **congestion charge**, must be deferred if necessary in order to expedite the implementation of the **benefit-based charge** for the **benefit-based investments** specified in clause 66.*	Our proposal is not to defer BBC implementation for low-value post-2019 BBIs, or any of the Additional Components we have adopted, to expedite implementation of high-value post-2019 BBIs. We do not consider this to be necessary. For completeness, clause 37(2) of the proposed TPM does allow us to delay the start of a BBC for a low-value post-2019 BBI if we are yet to obtain certain locational information. However, this is not a departure from the Guidelines.	See clause 3 and 37(2)
68.	*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 existing **benefit-based investments** referred to in clause 66 and*	Our proposal does not include a "phase in" mechanism for low-value post-2019 BBIs, as we are not proposing to defer their implementation for the purpose of expediting implementation of high-value BBIs.	Not applicable.

Clause	Guidelines requirement	How the proposed TPM meets the requirement	Reference
	no later than the date of ***commissioning*** *of the* ***investment*** *or five years after the commencement of the* ***TPM****, whichever is the later.*		