

Transpower's proposed variation to the Transmission Pricing Methodology

Consultation Paper

Submissions close: 5 p.m. on 2 June 2015

21 April 2015



Executive summary

Introduction

Transpower has carried out an operational review of the transmission pricing methodology (TPM). The TPM is Schedule 12.4 of the Electricity Industry Participation Code 2010 (Code).

Transpower considers, and the Electricity Authority (Authority) agrees, that:

- the regional coincident peak demand (RCPD) allocation of the interconnection charge can incentivise a higher level of demand response than is efficient – given that most regions of the country are not expected to face capacity constraints in the next few years
- in particular, the RCPD allocation can cause inefficient demand response in the summer months, including at the New Zealand Aluminium Smelters (NZAS) smelter
- the process for dealing with reverse flows is not clear enough.

To address these problems, Transpower has proposed that the TPM should be amended to:

- use, in the calculation of the interconnection charge, $N=100$ for all four RCPD regions
- exclude summer trading periods (i.e. from November to April inclusive) from the capacity measurement period used to calculate RCPD
- for the purpose of identifying regional peak demand periods in a region, require Transpower to disregard a change in a customer's offtake if Transpower is satisfied that:
 - the change would alter the incidence of most of the peaks in a relevant region
 - the customer would be unlikely to change their offtake absent Transpower disregarding that change
 - the change is unlikely to give rise to a need for transmission investment
- provide for Transpower to adjust transmission charges when a reverse flow situation occurs.

The Authority is now considering whether to amend the Code as proposed by Transpower. The Authority's process for considering Transpower's proposed variation is driven by both the Code and the Electricity Industry Act 2010 (Act).

Transpower also proposed to:

- allocate HVDC charges on a per-MWh basis, with an initial transition period

- allow NZAS to increase electricity consumption from 572 MW to 636 MW in the summer months without this being reflected in the calculation of RCPD
- adjust the formula for the line maintenance component of the connection charge, so that it is based on a four-year average of the line maintenance rate.

The Authority has referred these three proposals back to Transpower, and so is not consulting on them at this time.

Using N=100 for all four RCPD regions

This component of the proposed variation is expected to promote efficiency for the long-term benefit of consumers, by reducing the incentives for inefficient investment in, and operation of, demand response. This is expected to promote a more efficient (lower) level of transmission deferral.

Based on quantitative cost-benefit analysis, the Authority tentatively considers that the proposal is preferable to alternatives that are consistent with the current TPM Guidelines. However, the cost-benefit analysis is sensitive to some assumptions. Therefore, the Authority seeks more information about whether these assumptions are valid.

The Authority believes that there are superior alternatives that are not consistent with the current TPM Guidelines. Such alternatives could be considered as part of the Authority's review of the TPM.

Excluding summer trading periods from the capacity measurement period used for the calculation of RCPD

The proposed amendment is expected to promote efficiency for the long-term benefit of consumers, by removing an inefficient incentive for load parties (especially in the LSI) to reduce summer electricity consumption.

The proposal is expected to provide a net economic benefit relative to the status quo.

No alternative options that would better promote the statutory objective have been identified – with the possible exception of the proposal immediately below. Following consultation, the Authority may decide to proceed with one, both or neither of these two components.

Requiring Transpower to disregard changes in a customer's offtake for the purpose of determining regional peaks, if transmission investment not required

Again, this proposed amendment is expected to promote efficiency for the long-term benefit of consumers, by removing an inefficient incentive for load parties (especially in the LSI) to reduce summer electricity consumption.

The proposal is expected to provide a net economic benefit relative to the status quo.

No alternative options that would better promote the statutory objective have been identified – with the possible exception of the proposal immediately above. Following consultation, the Authority may decide to proceed with one, both or neither of these two components.

Providing for Transpower to adjust transmission charges when a reverse flow situation occurs

This component of the proposed variation is expected to promote efficiency for the long-term benefit of consumers, by supporting efficient investment in, and operation of, Transpower's customers' networks.

The Authority does not consider that the expected net benefit is very large. However it is probably greater than zero.

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1. What you need to know to make a submission

1.1 What this consultation paper is about

1.1.1 Transpower has carried out an operational review of the transmission pricing methodology (TPM). The TPM is Schedule 12.4 of the Electricity Industry Participation Code 2010 (Code).

1.1.2 Transpower considers, and the Electricity Authority (Authority) agrees, that:

- (a) the regional coincident peak demand (RCPD) allocation of the interconnection charge can incentivise a higher level of demand response than is efficient
- (b) in particular, the RCPD allocation can cause inefficient demand response in the summer months, including at the New Zealand Aluminium Smelters (NZAS) smelter
- (c) the process for dealing with reverse flows is not clear enough.

1.1.3 To address these problems, Transpower has proposed that the TPM should be amended to:

- (a) use, in the calculation of the interconnection charge, $N=100$ for all four RCPD regions¹
- (b) exclude summer trading periods from the capacity measurement period used for the calculation of RCPD
- (c) for the purpose of identifying peak demand periods in a region, require Transpower to disregard a change in a customer's offtake if Transpower is satisfied that:
 - (i) the change would alter the incidence of most of the peaks in the relevant region
 - (ii) the customer would be unlikely to change their offtake absent Transpower disregarding that change
 - (iii) the change is unlikely to give rise to a need for transmission investment
- (d) provide for Transpower to adjust transmission charges when a reverse flow situation occurs.

1.1.4 Transpower also proposed to:

- (a) allocate HVDC charges on a per-MWh basis, with an initial transition period

¹ Here, N refers to the number of regional coincident peaks that are averaged in calculating the allocation of the charge. At present, the Upper North Island (UNI) and Upper South Island (USI) regions use $N=12$, while the Lower North Island (LNI) and Lower South Island (LSI) regions use $N=100$.

- (b) allow NZAS to increase electricity consumption from 572 MW to 636 MW in the summer months without this being reflected in the calculation of RCPD
 - (c) adjust the formula for the line maintenance component of the connection charge, so that it is based on a four-year average of the line maintenance rate.
- 1.1.5 The Authority has referred these three proposals back to Transpower under clause 12.91(1)(b) of the Code, and so is not consulting on them at this time.
- 1.1.6 Drafting to give effect to Transpower's proposed amendments to the Code (in particular, a marked up version of the TPM) is attached as Appendix B.
- 1.1.7 The Authority is now considering whether to amend the Code as proposed by Transpower. The purpose of this paper is to consult with participants and persons that the Authority thinks are representative of the interests of those likely to be affected by the proposed amendments.
- 1.1.8 Section 39(1)(c) of the Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement. Section 39(2) provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. The regulatory statements for the proposed amendments are set out in Sections 4 to 8 of this paper.
- 1.1.9 To assist interested parties to formulate their submissions, this consultation paper includes specific questions about aspects of Transpower's proposed variation. However, the Authority is interested in receiving submissions on any aspect of Transpower's proposed variation.
- 1.1.10 The Authority invites submissions on the proposed amendments and regulatory statements.

1.2 How to make a submission

- 1.2.1 The Authority would prefer to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions, unless you cannot do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with 'Consultation Paper - Transpower's proposed variation to the TPM' in the subject line.
- 1.2.2 The Authority is likely to make your submission available to the public on the Authority's website. If you have attached any supporting documents, you should indicate this in a covering letter and clearly indicate any confidential information.

However, all information provided to the Authority is subject to the Official Information Act 1982.

- 1.2.3 If possible, provide your submission in the format shown in Appendix A. If you do not wish to send your submission electronically, post one hard copy of the submission to either of the addresses provided below or fax it to 04 460 8879. You can call 04 460 8860 if you have any questions.

Postal address

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Physical address

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

1.3 Deadline for receiving a submission

- 1.3.1 Submissions should be received by **5pm on Tuesday 2 June 2015**. Please note that late submissions are unlikely to be considered.
- 1.3.2 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

2. Background

2.1 The TPM sets out how Transpower recovers most of its costs

- 2.1.1 The TPM is Schedule 12.4 of the Code. It sets out how Transpower recovers the costs of providing the transmission grid, including the cost of capital, operations and maintenance, and overheads.
- 2.1.2 Some of Transpower's costs are not recovered under the TPM – including costs associated with:
- (a) providing system operator services, which are paid for under a contract between the Authority and Transpower
 - (b) investment contracts between Transpower and connected parties allowed for under clauses 12.70, 12.71 and 12.95 of the Code²
 - (c) some historical contracts agreed under the TPM that applied prior to 2008
 - (d) Transpower's activities that are not regulated under Part 4 of the Commerce Act 1986, and are not included in Transpower's Maximum Allowable Revenue (MAR) – such as its role as the FTR manager.
- 2.1.3 The three key components of the TPM are:
- (a) HVDC charges
 - (b) interconnection charges
 - (c) connection charges.
- 2.1.4 These three components are described in more detail in Appendix C.

2.2 Transpower may propose a variation to the TPM

- 2.2.1 Transpower may review the TPM and submit to the Authority a proposed variation to the TPM, provided the submission is at least a year after the last TPM was approved.³
- 2.2.2 Transpower's proposed variation to the TPM must be developed consistent with:⁴
- (a) any determination made under Part 4 of the Commerce Act 1986
 - (b) the Authority's statutory objective

² Note that operations and maintenance (O&M) costs for these assets are still recovered under the TPM.

³ Clause 12.85 of the Code.

⁴ Clauses 12.87 and 12.89 (1) of the Code.

- (c) the TPM Guidelines, which currently are those published by the Electricity Commission on 24 March 2006.⁵

2.3 Transpower has carried out an operational review of the TPM and proposed a variation

- 2.3.1 Transpower began an operational review of the TPM in May 2014, with the intention of '*addressing a number of potential problems identified with the current TPM*'.⁶
- 2.3.2 Transpower published an initial consultation paper in July 2014, and a second consultation paper in November 2014.⁷ There were 19 submissions on the initial consultation paper and 17 on the second consultation paper.
- 2.3.3 Appendix D briefly summarises the issues raised in the consultation papers and submissions.
- 2.3.4 Transpower also:
- (a) held stakeholder briefings in Auckland, Christchurch and Wellington
 - (b) held two rounds of bilateral discussions with stakeholders
 - (c) provided the Authority with regular progress updates.
- 2.3.5 On 13 February 2015, Transpower submitted to the Authority a proposed variation to the TPM. The submission consists of:⁸
- (a) a cover letter
 - (b) Attachment A, which consists of five separate Code amendment proposal forms – one for each component of the proposed variation
 - (c) Attachment B ('*Background and supporting information*'), which sets out Transpower's process, summarises the five components of the proposed variation, provides the rationale for each, and notes points raised in submissions
 - (d) Attachment C, which provides Transpower's proposed drafting (as opposed to the drafting in Appendix B of this paper, which has been revised by the Authority in consultation with Transpower)

⁵ <http://www.ea.govt.nz/dmsdocument/2990> Clause 17.118 of the Code deems the guidelines published by the Electricity Commission to be published by the Authority under clause 12.83 of the Code.

⁶ <https://www.transpower.co.nz/about-us/industry-information/tpm-development>

⁷ <https://www.transpower.co.nz/about-us/industry-information/tpm-development/tpm-operational-review-submissions>

⁸ <http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/development/operational-review-proposal-documents/>

- (e) Attachment D, which provides quantitative analysis and indicative pricing effects
- (f) a report by Scientia Consulting, and associated modelling files, in support of Transpower's analysis of the HVDC charge.

2.3.6 At the request of the Authority, Transpower subsequently provided additional information, to assist the Authority in its consideration of the proposed variation. The information included:

- (a) analysis of the consistency of Transpower's proposed variation with determinations made under Part 4 of the Commerce Act 1986 ⁹
- (b) Transpower's rationale for not including a transitional arrangement in its RCPD N=100 component ¹⁰
- (c) comments on the possible effects of the RCPD N=100 component on participant behaviour ¹¹
- (d) a sensitivity analysis of the CBA of the component proposing to allocate HVDC charges on a per-MWh basis ¹²
- (e) modelling files providing detailed workings of the CBA of the component proposing to allocate HVDC charges on a per-MWh basis ¹³
- (f) an explanation of aspects of how the proposal to allocate HVDC charges on a per-MWh basis would work. ¹⁴

2.3.7 The proposed variation and additional information are available on the Authority's website. ¹⁵

2.3.8 The best starting point for the reader may be:

- (a) Transpower's Code amendment proposals for the components that the Authority is consulting on, which are reproduced as Appendix E of this paper
- (b) Attachment B of Transpower's submission (*'Background and supporting information'*), which is reproduced as Appendix F of this paper.

2.3.9 Transpower's original proposed variation had five components:

⁹ Transpower TPM consistency with Part 4 determination: <http://www.ea.govt.nz/dmsdocument/19316>

¹⁰ RCPD N=100 transitional arrangement - <http://www.ea.govt.nz/dmsdocument/19317>

¹¹ Allocation effects RCPD - <http://www.ea.govt.nz/dmsdocument/19318>

¹² HVDC analysis – sensitivity report - - <http://www.ea.govt.nz/dmsdocument/19325>

¹³ http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2F20150421_Transpower_proposed_variation_to_TPM&parentDirectory=%2FDatasets%2FSupplementary_information%2F2015 - these files form part of the working of the CBA for the HVDC proposal.

¹⁴ HVDC proposal - - <http://www.ea.govt.nz/dmsdocument/19319>

¹⁵ <http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/development/operational-review-proposal-documents/>

- (a) to allocate HVDC charges on a per-MWh basis, with an initial transition period¹⁶
- (b) in the calculation of the interconnection charge, to use N=100 for all four RCPD regions¹⁷
- (c) for the purpose of the interconnection charge, to treat NZAS loads between 572 MW and 636 MW as if they were just 572 MW, during the period from November to April (hereafter referred to as the 'bespoke NZAS' component)¹⁸
- (d) to adjust the formula for the line maintenance component of the connection charge, so that it is based on a four-year average of the line maintenance rate¹⁹
- (e) to provide for Transpower to adjust transmission charges when a reverse flow situation occurs.

2.3.10 Following discussion with the Authority, Transpower went on to propose two new components, which were to:²⁰

- (a) exclude summer trading periods from the calculation of RCPD in all four RCPD regions (hereafter the 'amended RCPD capacity measurement period (CMP)' component)
- (b) require Transpower to disregard a customer's offtake changes in a region for the purpose of determining regional peak demand periods, in cases where a change in the customer's offtake would alter the incidence of a majority of peaks in the region, would not impact on transmission investment requirements, and would not occur in the absence of the adjustment for the change (hereafter the 'RCPD quantity adjustment provision' component).

¹⁶ As will be explained in the following section, this paper is not consulting on the HVDC component of the proposed variation – which has been referred back to Transpower.

¹⁷ At present, the Upper North Island (UNI) and Upper South Island (USI) regions use N=12, while the Lower North Island (LNI) and Lower South Island (LSI) regions use N=100.

¹⁸ As will be explained in the following section, this paper is not consulting on the 'bespoke NZAS' component – which has been referred back to Transpower.

¹⁹ As will be explained in the following section, this paper is not consulting on the line maintenance component of the proposed variation – which has been referred back to Transpower.

²⁰ <http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/development/operational-review-proposal-documents#march24>

- 2.3.11 The main differences from the proposals that Transpower consulted on in November 2014 are that:
- (a) Transpower was previously proposing to allocate HVDC charges on a 'diluted HAMI' basis, but is now instead proposing a per-MWh allocation
 - (b) Transpower is no longer proposing to derate HVDC charges in the Upper South Island (USI) region
 - (c) Transpower is no longer proposing to deal with the NZAS-related issue by amalgamating the Upper North Island (UNI), Lower North Island (LNI), and Lower South Island (LSI) regions. Instead, Transpower has proposed three other approaches, each of which would deal with the NZAS-related issue, which are:
 - (i) the 'bespoke NZAS' component
 - (ii) the 'amended RCPD CMP' component
 - (iii) the 'RCPD quantity adjustment provision' component.
- 2.3.12 Transpower considers that its proposed variation meets the requirements in clause 89(1) of the Code to be consistent with:
- (a) any determination made under Part 4 of the Commerce Act 1986²¹
 - (b) the Authority's statutory objective
 - (c) the TPM Guidelines.
- 2.3.13 Transpower states that the five original components of its proposed variation are straightforward to implement, low-cost, incremental, and broadly supported by the industry (though not necessarily by consensus).
- 2.3.14 Transpower seeks approval of its proposed variation by June 2015, so that:
- (a) changes to the TPM can be implemented by September 2015
 - (b) incentive effects on participants can take effect from 1 September 2015 – and hence efficiency benefits can accrue from that date
 - (c) the revised TPM can be used to calculate transmission charges from 1 April 2017.

²¹ Transpower TPM consistency with Part 4 determination: <http://www.ea.govt.nz/dmsdocument/19316>

2.4 The Authority's process for considering Transpower's proposed variation is driven by the Code and the Act

- 2.4.1 Clause 12.87 of the Code states that the Authority must follow the process in clauses 12.91 to 12.94 when reviewing a transmission pricing methodology.
- 2.4.2 The Authority's view is that the reference to 'reviewing a transmission pricing methodology' in clause 12.87 includes the Authority considering a proposed variation submitted by Transpower under clause 12.85.
- 2.4.3 Consequently, the Authority will follow the process in clauses 12.91 to 12.94 in responding to Transpower's proposed variation.
- 2.4.4 In doing so, the Authority has necessarily read the references in those clauses to 'Transpower's proposed transmission pricing methodology' as references to 'Transpower's proposed variation to the transmission pricing methodology'. Therefore, clause 12.91 requires the Authority to either:
- (a) approve the proposed variation having regard to the requirements of clause 12.89(1), or
 - (b) refer the proposed variation back to Transpower if it does not adequately conform with the requirements of clause 12.89(1).
- 2.4.5 Clause 12.89 requires Transpower to develop its proposed variation consistent with:
- (a) any determination under Part 4 of the Commerce Act
 - (b) the Authority's statutory objective
 - (c) the guidelines published under clause 12.83(b).
- 2.4.6 Further, the Authority reads the reference to 'approve' in clause 12.91(1)(a) as 'approve for consultation', given that clause 12.92 of the Code requires the Authority to publish the proposed variation for consultation.
- 2.4.7 Transpower's proposed variation has seven components. The Authority has considered whether it is open to the Authority to approve some of the components of the proposed variation for consultation, and refer some components back to Transpower.
- 2.4.8 The Authority is of the view that it would be consistent with the process in clause 12.91 to do so, unless doing so would undermine the integrity of the consultation process in relation to the components being progressed. For example, the integrity of the consultation process would be undermined if parties were prejudiced in their ability to assess and consider the components being progressed by not knowing what was proposed in respect of the component being referred back to Transpower.

- 2.4.9 Following consideration of Transpower's proposed variation, the Authority has decided to:
- (a) refer three components back to Transpower, on the basis that there are alternative options that better promote the statutory objective and/or are more consistent with the TPM Guidelines.²² These components are:
 - (i) the proposal to allocate HVDC charges on a per-MWh basis
 - (ii) the bespoke NZAS component
 - (iii) the proposal to adjust the formula for the line maintenance component of the connection charge
 - (b) approve for consultation the other four components, on the basis that they adequately conform (i.e. are consistent) with the Code requirements, and consult on those components under clause 12.92.
- 2.4.10 Accordingly, the Authority has released this consultation paper, which assesses only the four components that have been approved for consultation.
- 2.4.11 The Authority is of the view that the HVDC, 'bespoke NZAS' and line maintenance components can be referred back to Transpower without compromising the ability of interested participants to assess the four components presented in this consultation paper. However, the Authority is interested in any submissions from parties regarding their ability to assess and consider the components discussed in this paper.
- 2.4.12 Given that a change to the TPM is a change to the Code, this consultation paper also addresses the requirements of section 39 of the Act, which:²³
- (a) requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement
 - (b) provides that the regulatory statement must include:
 - (i) a statement of the objectives of the proposed amendment
 - (ii) an evaluation of the costs and benefits of the proposed amendment
 - (iii) an evaluation of alternative means of achieving the objectives of the proposed amendment.

²² Letter to Transpower CEO: <http://www.ea.govt.nz/dmsdocument/19326>

²³ The Authority need not meet these requirements if (a) the nature of the amendments is technical and non-controversial, or (b) there is widespread support for the amendment among the people likely to be affected by it, or (c) there has been adequate prior consultation so that all relevant views have been considered. However, in this instance, the Authority considers it is good practice to meet the requirements even if one or more of these exclusions applies.

- 2.4.13 In this consultation paper, the Authority has only considered alternative options that are consistent with the TPM Guidelines. Options that are not consistent with the current TPM Guidelines can instead be considered as part of the Authority's own review of the TPM (see Section 2.5).
- 2.4.14 This consultation paper includes an application of the Code amendment principles to each component of the proposed variation. In applying the Code amendment principles, the counterfactual used by the Authority is the status quo – rather than some other possible outcome of the Authority's review of the TPM.
- 2.4.15 In consultation with Transpower, the Authority has made some drafting changes for the purposes of this consultation, in order to clarify and give better effect to Transpower's intended proposal, as well as to be consistent with the Authority's drafting conventions in relation to the Code.
- 2.4.16 Within 40 business days of the end of the submission period (or such longer period as the Authority may allow), the Authority must consider submissions and decide whether to amend the TPM and (if a decision is made to amend the TPM) the date on which the Code amendment will come into force. As required by the Code, the Authority will consult with Transpower in determining a date on which the relevant Code amendments come into force. The Authority anticipates that it will be able to complete these processes in a shorter time frame.
- 2.4.17 Accordingly, the Authority anticipates setting out its decisions in a Decisions and Reasons paper, to be published in July 2015.
- 2.4.18 In deciding whether to incorporate each of the components of the proposed variation into the Code, the Authority will be guided by its statutory objective and the Code amendment principles.
- 2.4.19 If the Authority decides not to incorporate into the Code one or more of the components of the proposed variation that it has approved for consultation, then it may consider progressing alternative means of achieving the relevant objective(s). In this case, further consultation may be required.

2.5 In parallel, the Authority is carrying out its own review of the TPM

- 2.5.1 The Authority is currently reviewing the TPM.
- 2.5.2 The Authority's review is considering whether changes to the TPM, which would necessitate changes to the Guidelines, are required to better promote the statutory objective. The Authority's review therefore has a broader scope than Transpower's review, and focuses on changes that would promote efficient operation and investment.

- 2.5.3 Transpower's review is considering changes that could be made to the TPM within the existing guidelines that could better promote the statutory objective, with an emphasis on changes that could deliver near-term efficiency gains.
- 2.5.4 The Authority considers that the current TPM can be improved so as to better meet the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.
- 2.5.5 The Authority decided to advance the processes of reviewing the TPM by developing a second TPM issues paper (second issues paper) for consultation following consideration of submissions on the Authority's October 2012 paper "TPM: Issues and Proposals" (October 2012 issues paper) and information provided at the TPM conference held in Wellington 29 – 31 May 2013. The second issues paper will include revised draft guidelines to be followed by Transpower in developing a new TPM (as referred to in clause 12.89 of the Code).
- 2.5.6 Prior to developing a second issues paper, the Authority is further considering and consulting on key aspects of a revised TPM proposal through a series of working papers, which will provide key inputs into the second issues paper.
- 2.5.7 Working papers that the Authority has completed can be found at <http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/>.

3. Problem definition

This section of the paper explains the three problems identified by Transpower that motivate the four components of Transpower's proposed variation to the TPM (excluding the HVDC, line maintenance and bespoke NZAS components, which are not being consulted on in this paper).

In doing so, the Authority has drawn on – but not limited itself to – the material provided by Transpower.

3.1 The RCPD allocation of the interconnection charge can incentivise a higher level of demand response than is efficient

- 3.1.1 The RCPD allocation of the interconnection charge incentivises demand response at times that may turn out to be regional peak periods.
- 3.1.2 In this context, demand response includes:
- (a) reductions in electricity consumption
 - (b) increases in the output of existing embedded generation
 - (c) construction of new embedded generation.
- 3.1.3 It is well established that this incentive can be distortionary, particularly when there is ample transmission capacity (i.e. no capacity constraint).
- 3.1.4 The Authority's paper 'Transmission pricing methodology: problem definition relating to interconnection and HVDC assets'²⁴ of September 2014 ('problem definition paper') set out that the RCPD allocation may over-signal the need for load shedding at peak times, in all four regions²⁵ of New Zealand. The Authority noted that there was considerable uncertainty about the economic cost of load shedding at peak times, and represented this uncertainty through four scenarios:
- (a) *infrequent and cheap load reduction, small reduction in peak load* – economic cost estimated at approximately \$2 million present value
 - (b) *infrequent and cheap load reduction, large reduction in peak load* – economic cost estimated at approximately \$5 million present value
 - (c) *more frequent and expensive load reduction, small reduction in peak load* – economic cost estimated at approximately \$37 million present value

²⁴ <https://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c13929>

²⁵ Upper North Island, Lower North Island, Upper South Island and Lower South Island

- (d) *more frequent and expensive load reduction, large reduction in peak load* – economic cost estimated at approximately \$106 million present value.

3.1.5 The Authority assumed that this economic cost would be offset (in part or in whole) by the economic benefit of deferring transmission investment in the UNI and USI, estimated to be in the range of \$5-15 million present value.

3.1.6 The Authority's problem definition also set out that the RCPD allocation may over-signal the value of embedded generation. However, the Authority did not quantify the resulting inefficiency.

3.1.7 The Authority's problem definition paper also identified some inefficiencies that arise from levying a postage stamp interconnection charge on load. These types of inefficiencies are not discussed further in this paper, however, as they cannot be remedied within the current TPM Guidelines.

3.1.8 Transpower's proposal provides the following context:²⁶

- (a) capacity constraints into the UNI region have now been relieved, so there is little benefit in deferring further investment in this region
- (b) there is also '*limited deferral value available*' in the USI region, with the next significant upgrade investment (over \$20 million) expected in the mid-2020s, and the next major investment (over \$100 million) in the 2040s
- (c) the rate of the interconnection charge increased by more than 60% between 2008/09 and 2014/15, which has increased the incentive for demand response in potential regional peak periods
- (d) procured demand response (as opposed to demand response in response to the interconnection charge) has become a viable tool for deferring transmission investment.

3.1.9 Transpower's proposal proceeds to set out the view that:²⁷

- (a) the RCPD allocation now sends an excessively strong pricing signal in the UNI and USI regions
- (b) the economic cost of demand response responding to the interconnection charge exceeds the transmission deferral benefit.

3.1.10 Transpower has not estimated the net economic cost arising from the RCPD allocation, as such. However, Transpower has estimated that the net economic benefit of moving to a different allocation is \$10.6 million present value over

²⁶ Section 4 of Attachment B of Transpower's proposal.

²⁷ Section 5 of Attachment B of Transpower's proposal.

five years.²⁸ Transpower's cost-benefit analysis is discussed further in Section 4.6 of this paper.

- 3.1.11 On this basis, Transpower has proposed that the RCPD allocation should be calculated based on 100 regional peaks per year, rather than the current 12, for the UNI and USI regions (see Section 4). The Authority agrees.

Q1. Do you have any comments on the part of the problem definition that relates to the interconnection charge incentivising a higher level of demand response than is efficient?

3.2 The RCPD allocation can cause inefficient demand response in the summer months

- 3.2.1 In recent years, regional demand peaks in the UNI, LNI and USI regions have not occurred during the summer months.²⁹ Generally they occur in winter, driven in large part by cold weather in the morning or evening, but with low embedded generation output also playing a part.³⁰ This would still hold true even if 100 peaks were used in the calculation of RCPD, rather than 12, in the UNI and USI regions (as proposed in Section 4).
- 3.2.2 However, regional peaks in the LSI region often occur in the summer months. For instance:
- (a) in the 2011/12 capacity measurement period, 26 of the top 100 regional peaks in the LSI occurred in summer
 - (b) in 2012/13, 21 of the top 100 peaks in the LSI occurred in summer
 - (c) in 2013/14, 8 of the top 100 peaks in LSI occurred in summer.
- 3.2.3 One of the drivers of summer peak load in the LSI is irrigation. Low embedded generation output, high residential demand, and above-average demand at the NZAS smelter can also contribute to summer peaking.
- 3.2.4 As set out in the Authority's problem definition paper and Transpower's proposal:
- (a) the NZAS smelter can vary its production seasonally

²⁸ This benefit is separate from any benefits that may arise from avoiding inefficient demand response in the summer months – see next section.

²⁹ Throughout this paper, the period from November to April inclusive is denoted as 'summer', for consistency with the language used in Transpower's proposal.

³⁰ For this purpose, regional demand is calculated as gross load minus the output of embedded generation (and some grid-connected generation as well). If embedded generation output falls, then (all else being equal), regional demand will rise.

- (b) NZAS might sometimes wish to increase production during the summer months, in order to take advantage of below-average wholesale electricity prices
- (c) however, NZAS is deterred from doing so by the RCPD allocation of the interconnection charge. If NZAS increased production in the summer months, it might set a regional peak in the LSI and pay an increased level of interconnection charges.

3.2.5 The Authority estimated the resulting productive inefficiency to be between:

- (a) \$4 million present value (*assuming that the value of electricity to NZAS is \$60/MWh, and that the RCPD allocation would deter NZAS from increasing consumption in each of the next three summers*)
- (b) \$32 million present value (*assuming that the value of electricity to NZAS is \$80/MWh, and the RCPD allocation would deter NZAS from increasing consumption in each of the next ten summers*).

3.2.6 Transpower agreed with this assessment.

3.2.7 It is possible that other LSI consumers also use less electricity during summer peak times than they otherwise would, as a result of the RCPD allocation of the interconnection charge.

3.2.8 Demand response by NZAS and other LSI consumers could be efficient, to the extent that it led to network investment deferral. However, as will be shown, the scope for such deferral appears to be limited.

3.2.9 Transpower initially advised that *'we have reviewed the impact of a change to a summer peak on LSI on the transmission system and can confirm it would not create any capacity constraints or need for additional investment'* – while adding that *'we recognise that this may change in future and propose to review this provision as part of any future clause 12.85 reviews that Transpower undertakes'*.³¹

3.2.10 Transpower later refined this view, commenting:

'In our proposal, we stated that increased production by NZAS over the summer period would not affect transmission investment (in the short to medium term at least). While that remains the case and the LSI region is a winter peaking region, parts of the region (notably South Canterbury) that are summer peaking are constrained and in need of capacity expanding transmission investment.

'Constraints in the 110kV South Canterbury network have been relieved for several years through short term measures (such as bus splits, special protection schemes and distributor load control) but investment to expand capacity is

³¹ <http://www.ea.govt.nz/dmsdocument/19120>

unavoidable and imminent. Any investments in this area (to meet the GRS), including in the short term the measures described above, must also demonstrate net economic benefits as the lines in question are not part of the core grid.

*'We consider it unlikely that this investment could be economically deferred further through transmission pricing at this point (more generally, the lack of coincidence between peaks in the South Canterbury region and the wider LSI region mean that retaining the current CMP and RCPD settings (N=100) are unlikely to have any material impact on summer peak demand growth in the near term).'*³²

- 3.2.11 Therefore, reductions in summer electricity consumption in the LSI in response to the RCPD allocation of the interconnection charge are likely to be inefficient.
- 3.2.12 The same issue may arise in other regions in future:
- (a) Transpower notes that in the USI, summer peak is growing faster than winter peak, and the two may eventually converge
 - (b) It is possible that in the UNI, summer peak may grow faster than winter peak (e.g. as a result of increased use of air conditioning).
- 3.2.13 Therefore, some UNI and USI regional peaks could eventually occur in summer – particularly if these regions move to N=100 (as proposed in Section 4).
- 3.2.14 Demand response at summer peak times in the UNI or USI could be inefficient, if it did not result in substantial deferral of network investment.
- 3.2.15 Therefore, Transpower has proposed to exclude summer trading periods from the capacity measurement period used to calculate a customer's RCPD in all four RCPD regions (see Section 5 – describing the 'amended RCPD CMP' component).
- 3.2.16 For that matter, peaking demand response at other times of year and/or in other regions could be inefficient, if it did not result in substantial deferral of network investment.
- 3.2.17 Therefore, Transpower has proposed that it should be required to disregard customer's offtake changes in a region for the purpose of determining regional peak demand periods, in cases where a change in the customer's offtake would alter the incidence of a majority of peaks in the region, would not impact on transmission investment requirements, and would not occur in the absence of the adjustment for the change (see Section 6 – describing the 'RCPD quantity adjustment provision' component).

³² <http://www.ea.govt.nz/dmsdocument/19282>

- 3.2.18 These two proposals address essentially the same problem, but are not mutually exclusive. The Authority agrees that at least one of them should be progressed. The relationship between the two proposals is discussed in Section 7.

Q2. Do you have any comments on the part of the problem definition that relates to the RCPD allocation deterring some consumers from increasing consumption in the summer months?

3.3 The process for dealing with reverse flows is not clear enough

- 3.3.1 Reverse flow occurs when electricity flows from the grid into a connection location, through the network of a customer (usually a distributor), and back into the grid at another connection location.
- 3.3.2 When reverse flow occurs:
- (a) the quantity of offtake at the first connection location is not reflective of the amount of power consumed on the customer's network, and
 - (b) the quantity of injection at the second connection location is not reflective of the amount of power generated on the customer's network (if any).
- 3.3.3 Therefore, reverse flow can result in a customer's interconnection charge being larger than the customer considers it should be. Transpower considers that this may lead to allocatively inefficient signalling (though it also notes the effects may not be material). Transpower's proposal sets out one case where this situation has occurred, and one case where it *may* have occurred.³³
- 3.3.4 In theory, reverse flow can also result in a SI generator's HVDC charge being larger than the generator considers it should be, or a connected party's connection charge being larger than they consider it should be. However, Transpower has not provided any examples of these kinds of situations.
- 3.3.5 Transpower's proposal sets out that Transpower's current practice, when a customer alleges that reverse flows have affected transmission charges, is to:³⁴
- (a) consider whether reverse flows have affected transmission charges
 - (b) if this is the case, consider declaring 'exceptional operating circumstances'³⁵ and adjusting charges to remove the effect of reverse flows.

³³ See Section 9 of Attachment B of Transpower's proposal.

³⁴ See Section 9 of Attachment B of Transpower's proposal.

³⁵ Clause 34(2) of the TPM

- 3.3.6 This practice, however, does not provide customers with certainty. A customer cannot be sure in advance whether Transpower will declare 'exceptional operating circumstances' if reverse flows occur on that customer's network.
- 3.3.7 There is a risk that this uncertainty will result in inefficient outcomes, if distributors:
- (a) reconfigure their networks to prevent reverse flow situations from occurring
 - (b) are deterred from investing in distribution network assets that could give rise to reverse flows.
- 3.3.8 Transpower's reasoning is discussed further in Section 8 of this paper.
- 3.3.9 In order to provide customers with more certainty, Transpower has proposed to amend the Code to provide for Transpower to adjust transmission charges when Transpower considers that a reverse flow situation has occurred (see Section 8). The Authority agrees.

Q3. Do you have any comments on the part of the problem definition that relates to the treatment of reverse flows?

4. Regulatory statement for Transpower's proposal that the RCPD allocation should use N=100 for all four regions

4.1 Transpower's proposal

- 4.1.1 Transpower proposes that the RCPD allocation of the interconnection charge should use N=100 for all four regions. That is, the allocation should be based on the top 100 coincident demand peaks in each region in each year. At present it is based on:
- (a) the top 12 peaks in each of the UNI and USI regions
 - (b) the top 100 peaks in each of the LNI and LSI regions.
- 4.1.2 Other Code provisions relating to the interconnection charge would be unchanged (aside from the changes proposed in Sections 5 and 6).
- 4.1.3 In connection with this proposal, a minor change has been proposed to Appendix B of the TPM, to omit the tables of connection locations that existed at the time the current TPM came into force. The tables are out of date and function mainly as an illustration of the connection locations covered by the description of each region.

4.2 Impacts on participants

- 4.2.1 Transpower has provided a spreadsheet that shows indicative impacts on the RCPD rate.³⁶ The analysis is based on several scenarios with varying levels of demand response. Under all demand response scenarios considered, the RCPD rate is slightly lower than under the status quo.
- 4.2.2 The Authority takes a different view on the RCPD rate, anticipating that it would be slightly *higher* under the proposal than under the status quo. The reason is that mean UNI and USI demand, averaged over the top 100 trading periods, is expected to be lower than mean UNI and USI demand, averaged over the top 12 trading periods.
- 4.2.3 The Authority anticipates that, under Transpower's proposal:
- (a) most consumers in the UNI and USI that respond to RCPD signals would either pay an increased share of interconnection costs, or incur increased demand response costs, relative to the status quo

³⁶ Sheet 'Allocation effects RCPD' of "8 Attachment_D_TPM_OpRev_Price_Effects_and_RCPD_avoided costs_13Feb2015.xlsx", which can be downloaded at <http://www.ea.govt.nz/dmsdocument/19123>.

- (b) consumers in the UNI and USI that do not respond to RCPD signals:
 - (i) would typically pay a lower share of interconnection costs – because their RCPD quantity was lower over 100 peaks than over 12 peaks, but
 - (ii) could in some cases instead pay a higher share of interconnection costs, either because their RCPD quantity happened to be lower over 12 peaks than over 100 peaks, or because the RCPD rate would be slightly higher than under the status quo
- (c) embedded generators in the UNI and USI that receive avoided cost of transmission (ACOT) payments:
 - (i) if they had a medium to high short-run marginal cost (SRMC), would either receive reduced ACOT revenue or incur increased generation costs, relative to the status quo
 - (ii) if they had a low SRMC, could receive slightly increased ACOT revenue – because the RCPD rate would be slightly higher than under the status quo – and would probably also experience less volatility in ACOT payments from year to year
- (d) consumers in the LNI and LSI would pay a slightly higher share of interconnection costs – because the RCPD rate would be slightly higher than under the status quo
- (e) embedded generators in the LNI and LSI that receive ACOT payments would receive slightly higher revenue, regardless of their SRMC – because the RCPD rate would be slightly higher than under the status quo.

4.3 The objectives of the proposed amendment

4.3.1 In the Authority's view, the proposed amendment has two objectives:

- (a) to promote efficiency by reducing the incentives for:
 - (i) inefficient investment in demand response (including embedded generation) in the UNI and USI
 - (ii) inefficient operation of demand response (including embedded generation) in potential regional peak periods in the UNI and USI
- (b) to continue to achieve the transmission deferral benefits that stem from the RCPD allocation of the interconnection charge.

4.3.2 Transpower does not set out these two objectives explicitly, but in the Authority's view they are implicit in Transpower's reasoning.

4.3.3 In some cases there is a trade-off between the two objectives. If an amendment reduces the incentive for demand response at regional peak times, then the

economic cost of such a response may be partly or wholly avoided – but the longer-term result may be that transmission investment is brought forward.

- 4.3.4 In cases where there is no capacity constraint, then there is no need for demand response at regional peak times (except where this is indicated by the spot price) and only the first objective is a factor. In such cases, it is preferable to have an interconnection charge that is as non-distortionary as possible.
- 4.3.5 Transpower appears to place more weight on the first objective than the second, because it expects that relatively little transmission investment will be necessary to meet regional peak demand in the next few years. In other words, Transpower considers that the inefficiency arising from using N=12 in the UNI and USI outweighs any efficiency gains from transmission investment deferral. Section 4 of Attachment B of Transpower's proposal (attached as Appendix F of this paper) explains Transpower's reasons – which are based on its view of the transmission investment outlook.
- 4.3.6 Nevertheless, Transpower does place some weight on the second objective – commenting approvingly that *'the price signal provided by N=100 is likely to continue to stimulate a significant ongoing [demand] response'*. If Transpower did not place some weight on the second objective, it would presumably have proposed a less distortionary 'postage stamp' option such as a per-MWh charge on load.
- 4.3.7 It could be suggested that another objective should be to continue to achieve *distribution* network deferral benefits that stem from the RCPD allocation of the interconnection charge. However, Transpower's Code amendment proposal does not suggest that this is an objective of the proposal, and the Authority does not consider that it should be an objective. Signals for efficient deferral of distribution network investment should stem from distribution pricing and the Commerce Commission's regulatory framework, rather than from the interconnection charge.
- 4.3.8 It could be suggested that the RCPD allocation of the interconnection charge creates energy market dispatch benefits, and that another objective should be to continue to achieve such benefits. However, Transpower's Code amendment proposal does not suggest that this is an objective of the proposal, and the Authority does not consider that it should be an objective. Nor does the Authority agree that the RCPD allocation results in dispatch benefits. Signals for efficient production and consumption of energy stem from the wholesale market spot price, rather than from the interconnection charge.

4.4 The proposed amendment is expected to meet the objectives

- 4.4.1 The Authority's tentative view is that the proposed amendment would achieve the first objective of promoting efficiency with regard to investment in, and operation of, demand response.
- 4.4.2 The proposed amendment would:
- (a) reduce the incentive for demand response in the UNI and USI to operate in periods that participants anticipate will be 'top 12' regional peaks
 - (b) increase the incentive for demand response in the UNI and USI to operate in periods that participants anticipate will be 'top 100' regional peaks, but not 'top 12' regional peaks
 - (c) reduce the incentive for investment in new demand response capacity with high SRMC in the UNI and USI³⁷
 - (d) have relatively little effect on the incentive for investment in new demand response capacity with lower SRMC in the UNI and USI
 - (e) have relatively little effect on the incentives of participants in the LNI and LSI.
- 4.4.3 These trade-offs are explored further in Section 4.6.
- 4.4.4 Based on current information, the Authority considers that the net effect on efficiency with regard to investment in, and operation of, demand response would be positive.
- 4.4.5 The consultation questions at the end of this Section seek more information from submitters, in order to help the Authority to decide with more confidence whether the net effect would be positive or negative.
- 4.4.6 The Authority agrees that the proposed amendment would meet the second objective to some extent. Under the proposal, the RCPD allocation of the interconnection charge should continue to yield some transmission deferral benefits. The level of transmission deferral benefit is likely to be less than would be achieved under the current RCPD allocation (i.e. with N=12 in the UNI and USI). However, as is shown in Section 4.6, this reduction in deferral benefit is likely to be efficient – because the current allocation produces excessively strong signals for demand response.
- 4.4.7 The consultation questions at the end of this Section seek more information from submitters, in order to help the Authority to form a view on the transmission deferral effects.

³⁷ Which is a good thing, to the extent that such demand response is not needed to defer or avoid transmission investment

4.5 The Authority has considered other options for addressing the objective, but tentatively considers the proposed amendment is preferable

4.5.1 Transpower considered the following alternative options for the interconnection charge:

- (a) retaining the RCPD allocator but using a higher N (i.e. greater than 100)
- (b) a per-MWh charge on all load
- (c) a per-MWh charge on winter load only
- (d) a 'tilted postage stamp' charge on all load
- (e) an anytime maximum demand (AMD) charge.

4.5.2 Transpower considered that its proposal was superior to all these alternatives.

4.5.3 The Authority has not considered the winter per-MWh charge further. The Authority anticipates that this option would be more distortionary than the year-round per-MWh charge, because the year-round charge would be closer to being a flat tax. Further, the winter charge would not achieve substantially more transmission deferral, because it would not incentivise peaking demand response.

4.5.4 The Authority has not considered the 'tilted postage stamp' charge further, on the grounds that the LRMC-based option described later in this section is a better way of achieving the same end.

4.5.5 The Authority has not considered the AMD charge further. The Authority anticipates that this option would create an inefficient incentive for mass-market loads to curtail, or to be controlled, at the local network peak, irrespective of whether this affected regional peak load. This response would cause significant economic costs, without resulting in significant deferral of major transmission investment.

4.5.6 The Authority has, however, considered two of Transpower's alternative options further. These are the per-MWh charge on all load and the 'higher N' option.

4.5.7 The Authority has also considered an option that is a 50-50 mix of the current RCPD allocation (with N=12 for UNI and USI, and N=100 for LNI and LSI) and a per-MWh charge on load. In other words, half the amount to be recovered is allocated using RCPD, and the remaining half through a per-MWh charge. This option represents another way of balancing the competing objectives, while remaining within the TPM Guidelines.

4.5.8 The Authority has also considered an option that is based on the long-run marginal cost (LRMC) of transmission. Under this option, there would be a charge on load at times of regional peak demand, with the charge in each region linked to the

estimated LRMC of providing additional transmission capacity into that region. All remaining costs would be recovered through a per-MWh charge.

- 4.5.9 For the purpose of this paper, the Authority has assumed that the LRMC-based charge would apply to four regions (UNI, LNI, USI and LSI), and that the charge for each load customer in each region would be equal to that load customer's RCPD quantity (over N=100 regional peaks), multiplied by an estimated LRMC of:
- (a) \$10/kW per year in the UNI
 - (b) \$15/kW per year in the USI
 - (c) \$0/kW per year in the LNI and LSI.
- 4.5.10 The derivation of these indicative estimates of LRMC is set out in Appendix G.
- 4.5.11 For instance, a distributor in the USI that had an RCPD quantity of 50 MW (over N=100 regional peaks) would pay:
- (a) an LRMC-based charge of $50 * 1000 * 15 = \$750,000$ per year
 - (b) a per-MWh charge on their gross load.
- 4.5.12 If the same distributor was instead located in the LSI, they would pay the same per-MWh charge, but no LRMC-based charge.
- 4.5.13 LRMC would be estimated by Transpower, perhaps annually, based on information from Transpower's ten year expenditure and demand forecasts, which are published as part of the Commerce Act 1986 Part 4 regulatory regime.
- 4.5.14 Again, this option represents another way of balancing the competing objectives, while remaining within the Guidelines.
- 4.5.15 The Authority considers that the main advantages of an LRMC-based charge are that:
- (a) it is 'market-like' – that is, it would produce outcomes consistent with prices that would be set in a workably competitive market
 - (b) it would provide efficient signals for operation and investment.
- 4.5.16 When considering per-MWh charges on load, the Authority has assumed that such charges would be levied on *gross load* rather than *net load*, to the extent practicable. That is, the Authority has assumed that the charge will be proportional to total consumption, rather than consumption minus embedded generation. The reason for this assumption is that a per-MWh charge is intended to be non-distortionary. To the extent that the charge is based on gross load, it avoids distorting investment in embedded generation.
- 4.5.17 The main difficulty in applying a charge to gross load would lie in *measuring* gross load. The most likely approach would be to take net load at the GXP level and add

on the metered output of embedded generation, to the extent that it is available. It is likely that meter data will be available for larger embedded generators (such as grid scale wind farms), but not for smaller embedded generators (such as rooftop solar panels).

4.5.18 Section 4.6 therefore evaluates:

- (a) the proposal
- (b) the status quo
- (c) a per-MWh charge on gross load
- (d) a RCPD option with N=500 in all four regions
- (e) an option that is a 50-50 mix of the status quo and a per-MWh charge on gross load
- (f) an option that is a combination of a regional LRMC-based charge and a per-MWh charge on gross-load.

4.5.19 Appendix H explains how all these options are consistent with the TPM Guidelines requirement that 'charges for existing and new interconnection assets should be on a postage stamp basis'.³⁸

4.5.20 Section 4.6 tentatively concludes that, under base case assumptions, the proposal is the most preferable of these options. However, there are other sets of assumptions under which the status quo, or an alternative option, is preferable.

4.5.21 The remainder of this section raises other possible alternative options and explains why they have not been considered further.

4.5.22 Another alternative would be a capacity charge on load. In the context that Transpower is only able to propose changes to the TPM within the existing Guidelines, the Authority considers this option is less preferable, because it would not meet the second objective of the proposal (i.e. to continue to achieve efficient transmission deferral benefits).

4.5.23 The Authority considers that *if* a more efficient charge based on the guidance provided by the Authority's TPM decision-making and economic framework – e.g. a market, market-like or beneficiaries-pay charge – was in place to send an appropriate signal to TPM charge payers, then a capacity charge on load could potentially be an efficient way to recover the remaining costs. This option is considered as part of the Authority's own review of the TPM. The capacity charge on load would probably not be sufficient on its own, however, as it would not provide a signal for actions to efficiently defer transmission investment.

³⁸ Guideline 12.

- 4.5.24 Another alternative would be a RCPD charge in which the value of N varied over time – with N being small when transmission investment deferral is desired, and large when there is ample transmission capacity. The Authority considers that this option need not be considered further, because the same outcome could be achieved under the proposal – simply by waiting until significant transmission investment neared, and then initiating a new Code amendment proposal to reduce the value of N.
- 4.5.25 Another alternative would be the same as the proposal, but with an initial transition period. The Authority considers this option is less preferable, because it would delay the efficiency benefits of the proposal. The Authority notes that the TPM Guidelines set out that *‘transitional arrangements should be proposed where revision of the methodology leads to large increases or decreases in current charges’*, but agrees with Transpower’s view that the changes in charges arising from changing N to 100 in the UNI and USI would not be ‘large’.³⁹

Conclusion

- 4.5.26 The Authority tentatively concludes that the proposal is preferable to alternatives that are consistent with the current TPM Guidelines.
- 4.5.27 The Authority believes that there are superior alternatives that are *not* consistent with the current TPM Guidelines. Such alternatives will be considered as part of the Authority’s review of the TPM.

4.6 Assessment of costs and benefits

- 4.6.1 Transpower provided an indicative assessment of costs and benefits of the proposal versus the status quo. The analysis considered the following efficiency effects from altering N:
- (a) Benefit – an expected reduction in the use of inefficient demand response – i.e. activity that occurs to avoid transmission charges, but which has a cost that is greater than the benefit to society. Increasing the value of N would reduce the incentive on parties to undertake avoidance activity targeted at the 12 regional peak demand periods.
 - (b) Costs:
 - (i) a potential increase in economically inefficient demand control/local back-up generation. This could occur if some parties extended their peak avoidance activity to target the 100 highest peak demand periods, rather than the 12 highest.

³⁹ Response to RCPD transition query: <http://www.ea.govt.nz/dmsdocument/19317>

- (ii) a potential reduction in transmission deferral incentives – and hence higher transmission costs over time.

- 4.6.2 Transpower's analysis included a point estimate of gross benefit of \$10.6 million (present value over five years). This estimate was based on broad assumptions about the magnitude and costs of demand response under different values of N. The assessment did not include quantitative estimates for the cost components, but considered that they were unlikely to be significant.
- 4.6.3 The Authority has developed a more detailed analysis, in order to:
 - (a) quantify costs as well as benefits
 - (b) explore how sensitive the results are to changes in assumptions
 - (c) allow alternative options to be assessed
 - (d) allow other sources of potential benefits and costs to be assessed.
- 4.6.4 The Authority's analysis (like Transpower's) is based on a number of assumptions, some of which are based on limited hard data. Further, the conclusion of the analysis is sensitive to these assumptions.
- 4.6.5 The Authority is using this consultation to seek more information about whether these assumptions are reasonable. This feedback will help the Authority to make decisions on which option would have the greatest net economic benefit.

The Authority's cost-benefit analysis

- 4.6.6 This section summarises the quantitative cost-benefit analysis (CBA) of:
 - (a) the proposal
 - (b) the status quo
 - (c) a per-MWh charge on gross load
 - (d) a RCPD option with N=500 in all four regions
 - (e) an option that is a 50-50 mix of the status quo and a per-MWh charge on gross load
 - (f) an option that is a combination of a regional LRMC-based charge and a per-MWh charge on gross-load.
- 4.6.7 The CBA considers the following costs and benefits:
 - (a) the cost of peak avoidance activity by demand response (*which is maximised by the status quo RCPD charge in regions where N=12, and is minimised by a per-MWh charge*)

- (b) the benefit of deferring transmission investment (*which, again, is maximised by the status quo RCPD charge in regions where N=12, and is minimised by a per-MWh charge*)
 - (c) the cost of inefficient investment in embedded baseload and intermittent generation (*which is minimised by a per-MWh charge on gross load*)
 - (d) the deadweight loss arising from overall reductions in electricity consumption by some export oriented major industrial consumers (*which is maximised by a per-MWh charge*).
- 4.6.8 The CBA considers alternative charging regimes compared to the status quo, and assesses the present value of benefits and costs over 15 years, discounted at 8%.
- 4.6.9 The analysis incorporates various assumptions about factors such as the amount of demand response available, the way it may respond under the various options, the cost of doing so, and the extent of transmission deferral benefits available.
- 4.6.10 Further detail on the CBA is set out in Appendix I. The Authority is also making the CBA spreadsheet available on its website so submitters can perform their own sensitivity analysis if they wish.⁴⁰
- 4.6.11 The base case assumptions include that:
- (a) it is more likely than not that substantial new transmission investment will be required, absent any clear peak avoidance signal (i.e. that the long run marginal cost of transmission is in the order of \$80/kW per year in the UNI and USI, and on the order of \$40/kW per year in the LNI and LSI)⁴¹
 - (b) elastic industrial load is assumed to be 9,000 GWh with a price elasticity of -1.5
 - (c) interconnection charges are assumed to have no impact on embedded baseload and intermittent new generation investment.
- 4.6.12 A range of alternative sensitivity cases are considered.
- (a) Case A - this is the same as the base case, except that it assumes a lower likelihood of transmission investment being required in the absence of a clear peak avoidance signal, and that inefficient investment in 350 GWh/yr of new embedded baseload and intermittent generation beyond year 5 may occur, depending on the interconnection charge price signal.

⁴⁰ CBA for RCPD N=100 - <http://www.ea.govt.nz/dmsdocument/19324> (zip file)

⁴¹ These LRMCs are substantially higher than those estimated in the Authority's options working paper. In order for them to be correct, it would need to be the case that continued demand growth would result in major transmission investment – beyond the modest investment needs currently anticipated by Transpower for the next 10-15 years.

- (b) Case B - the same as Case A, except that elastic industrial load is assumed to be somewhat lower (7,000 GWh, c.f. 9,000 GWh in the Base Case) and is less sensitive to price changes.
- (c) Case C - the same as Case B, except that it assumes a further lowering of the likelihood of transmission investment being required in the absence of a clear peak avoidance signal, and industrial load has a further reduction in its price sensitivity.
- (d) Case D - the same as Case C, except that there is no likelihood of transmission investment being required in the absence of a clear peak avoidance signal.

4.6.13 At this stage the Authority takes no view as to the relative probabilities of the base case and the four sensitivity cases. The Authority is not necessarily asserting either that the base case holds, or that any one of the five cases considered holds. The cases are merely chosen in order to illustrate how the conclusion depends on the input assumptions.

4.6.14 Table 1 summarises the results of the CBA, and summarises the key assumptions for each case. The preferred option under each set of assumptions is marked with a grey box.

Table 1 Results of the CBA of interconnection charge options

	Base	Case A	Case B	Case C	Case D
Status Quo (N=12 UNI/USI, N=100 LNI/LSI)	\$0	\$0	\$0	\$0	\$0
a) N=100 all Regions	\$5	\$6	\$6	\$17	\$10
b) N=500 all Regions	\$3	\$24	\$24	\$46	\$47
c) 50:50 Gross MWh, Status Quo	\$4	\$12	\$30	\$49	\$43
d) LRMC & Gross MWh	-\$88	-\$61	\$4	\$48	\$48
e) Gross MWh	-\$108	-\$71	\$2	\$53	\$58

(Note: The figures shown are expected net economic benefits, relative to the status quo option. They are expressed in millions of dollars, present value over 15 years.)

4.6.15 Under the base case, the proposal has the highest expected net economic benefit – approximately \$1 million present value greater than the next best option.

4.6.16 However:

- (a) under sensitivity case A, the RCPD option with N=500 has the highest expected net economic benefit – approximately \$12 million present value greater than the next best option

- (b) under sensitivity case B, the 50-50 mix of the status quo and a per-MWh charge on gross load has the highest expected net economic benefit – approximately \$6 million present value greater than the next best option
- (c) under sensitivity case C, the per-MWh charge has the highest expected net economic benefit – approximately \$5 million present value greater than the next best option
- (d) under sensitivity case D, the per-MWh charge has the highest expected net economic benefit – approximately \$10 million present value greater than the next best option.

- 4.6.17 The results highlight the sensitivity of outcomes to the input assumptions. Broadly speaking, if there is a significant chance of substantial new transmission investment being required in the absence of an interconnection price signal, then an RCPD regime with $N=100$ or $N=500$ is preferred. If there is little or no likelihood of major transmission investment being required to meet demand growth, then an interconnection charge regime without a pronounced peak avoidance signal is preferred because it will induce less inefficient peak avoidance activity and investment in embedded baseload and intermittent generation.
- 4.6.18 The other important issue is the extent to which deadweight losses may arise. If there is a significant risk of deadweight losses, a charging regime that is intermediate between $N=12$ and per-MWh is likely to be preferable.
- 4.6.19 The conclusion is that under base case assumptions, the proposal is the most preferable of the options considered. However, there are other sets of assumptions under which an alternative option is preferable.
- 4.6.20 The status quo is not the preferred option under any of the sensitivities considered.
- 4.6.21 The consultation questions at the end of this section seek more information about how participant behaviour might be affected by each of the options considered. Such information could be used to estimate the assumptions above with more precision, and hence to reach a decision on which of the options is preferable.

4.7 Assessment under section 32(1) of the Act

- 4.7.1 Section 32(1) of the Act provides that Code provisions must be consistent with the Authority's objective and be necessary or desirable to promote any or all of the following:
- (a) competition in the electricity industry
 - (b) the reliable supply of electricity to consumers
 - (c) the efficient operation of the electricity industry

- (d) the performance by the Authority of its functions
- (e) any other matters specifically referred to in the Act as a matter for inclusion in the Code.

4.7.2 Table 2 sets out an assessment of the proposed amendment against the requirements of section 32(1) of the Act.

Table 2: How the proposal to use N=100 for all regions complies with section 32(1) of the Act

Requirement	Comment
The proposed amendment is consistent with the Authority's objective under section 15 of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.	<i>[Tentative view:]</i> The proposed amendment is expected to promote efficiency for the long-term benefit of consumers, by reducing the incentives for inefficient investment in, and operation of, demand response. The proposed amendment is expected to have no material effect on competition or reliability.
The proposed amendment is necessary or desirable to promote any or all of the following:	
(a) competition in the electricity industry;	The proposed amendment is not expected to materially affect competition.
(b) the reliable supply of electricity to consumers;	The proposed amendment is not expected to materially affect reliability.

(c) the efficient operation of the electricity industry;	<i>[Tentative view:]</i> The proposed amendment is expected to promote efficiency by reducing the incentive for inefficient demand response in potential regional peak periods in the UNI and USI. The proposed amendment is expected to support dynamic efficiency by promoting a more efficient (i.e. lower) level of transmission deferral. In particular, while demand response is still required to defer transmission investment, the strength of this incentive should be lower because of the large recent investment in the UNI, while in the USI significant transmission investment is not expected to be required for some time.
(d) the performance by the Authority of its functions;	The proposed amendment will not materially affect the performance by the Authority of its functions.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendment will not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

4.8 Assessment under the Code amendment principles

4.8.1 Table 3 describes the Authority's consideration of the Code amendment principles in assessing the proposal.

Table 3: Application of Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	<i>[Tentative view:]</i> The proposal provides clearly identified efficiency gains relative to the status quo and the other options considered in the CBA.

Principle	Comment
3. Net benefits are quantified	Net benefits have been quantified, although considerable uncertainty remains at this point.
<i>Because the assessment of costs and benefits is inconclusive as to which option is preferable, the Authority has applied principles 4-8.</i> <i>If, following consultation, the Authority reached the conclusion that the proposal would provide a net expected economic benefit relative to the status quo and the alternative options, then it would no longer be necessary to apply principles 4-8.</i>	
4. Preference for small-scale 'trial and error' options	Neither the proposal, nor any of the alternative options, is a small-scale 'trial and error' option. All the options considered would affect many participants, and would be difficult to change quickly if they proved unsatisfactory.
5. Preference for greater competition	Neither the proposal, nor any of the alternative options, is expected to have a material effect on competition.
6. Preference for market solutions	All options considered provide for charges to be calculated administratively, rather than through a market.
7. Preference for flexibility to allow innovation	Neither the proposal, nor any of the alternative options, is specifically designed to promote innovation. However, to the extent that they created incentives for demand response, they would encourage the development of more efficient demand response options in the region(s) concerned.
8. Preference for non-prescriptive options	All options considered are prescriptive.

- Q4. In your view, how would participants change their behaviour if the RCPD allocation used N=100 in the UNI and USI regions? What would be the economic costs and benefits of this change in behaviour?**
- Q5. In your view, how would participants change their behaviour if the RCPD allocation used N=500 in all four regions? What would be the economic costs and benefits of this change in behaviour?**
- Q6. In your view, how would participants change their behaviour if the interconnection charge was a per-MWh charge on gross load? What would be the economic costs and benefits of this change in behaviour?**
- Q7. In your view, how would participants change their behaviour if the interconnection charge was a 50-50 mix of the status quo and a per-MWh charge on gross load? What would be the economic costs and benefits of this change in behaviour?**
- Q8. In your view, how would participants change their behaviour if the interconnection charge was a combination of a regional LRMC-based charge and a per-MWh charge on gross-load? What would be the economic costs and benefits of this change in behaviour?**
- Q9. Do you consider that the proposal in Section 4 (i.e. that the RCPD allocation should use N=100 for all four regions) is preferable to the status quo and other options? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.**
- Q10. Do you consider that the proposal in Section 4 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?**
- Q11. Do you have any comments on the drafting of the proposal in Section 4, which is included in Appendix B?**

5. Regulatory statement for Transpower's 'amended RCPD CMP' component

5.1 Transpower's proposal

- 5.1.1 Transpower proposes that the period between November and April inclusive should not be part of the capacity measurement period used to identify regional peaks for the calculation of the RCPD allocation of the interconnection charge. This proposal would apply to all four RCPD regions.
- 5.1.2 In other words, the RCPD allocation would be based on peaks occurring between 1 May and 30 October only.

5.2 Impacts on participants

- 5.2.1 Initially, the main participant affected would be NZAS. NZAS would be able to increase summer load without incurring additional interconnection charges.
- 5.2.2 Other LSI consumers that are exposed to the RCPD allocation of the interconnection charge might also be affected:
 - (a) if they use more electricity in winter than in summer, they could be worse off
 - (b) conversely, if they use more electricity in summer than in winter, they might be better off
 - (c) like NZAS, they could potentially benefit by increasing their summer load, relative to what it would otherwise have been.
- 5.2.3 Initially, participants in other regions would not be substantially affected, as:
 - (a) the RCPD rate would not be substantially different from what it would have been under the status quo
 - (b) regional peaks in the UNI, LNI and USI are unlikely to occur in summer in the next few years, even in the absence of the amendment.
- 5.2.4 However, in the longer term, participants in the UNI and/or USI might be affected, if either of these regions became more summer-peaking.

5.3 The objectives of the proposed amendment

- 5.3.1 The objective of the proposed amendment is to remove an incentive for inefficient demand response in the summer months, which is created by the RCPD allocation of the interconnection charge.

5.4 The proposed amendment is expected to meet the objective

- 5.4.1 Under the proposed amendment, the RCPD allocation of the interconnection charge will no longer incentivise demand response between November and April inclusive.

5.5 The Authority has considered other options for addressing the objective, but considers the proposed amendment is preferable

- 5.5.1 Alternative options raised by Transpower include:
- (a) the 'bespoke NZAS' component – i.e. allowing NZAS to increase electricity consumption from 572 MW to 636 MW in the summer months without this being reflected in the calculation of RCPD
 - (b) creating a new RCPD region including only the NZAS smelter
 - (c) amalgamating the LSI, LNI and UNI regions into a single RCPD region – so that regional peaks in the 'super-region' would not occur in the summer months
 - (d) the 'RCPD quantity adjustment provision' component proposed in Section 6.
- 5.5.2 The Authority has not considered the 'bespoke NZAS' component further, because it is a bespoke solution that only applies to a single participant. Bespoke solutions are not preferred, because they hinder dynamic efficiency by encouraging other participants to lobby for special treatment.
- 5.5.3 The Authority has not considered further the option of putting the NZAS smelter in its own RCPD region. Transpower and the Authority agree that this option would not achieve the objectives set out in Section 5.3.
- 5.5.4 The Authority has not considered further the option of creating a single 'super-region'. This option would not incentivise operation of demand response to reduce UNI regional peak demand. Rather, demand response would operate to reduce UNI/LNI/LSI super-regional peak demand – which is not a driver of transmission investment. Therefore, this option would not achieve efficient deferral of any UNI transmission investment needs that become apparent in future.
- 5.5.5 Another option would be to exclude summer trading periods from the calculation of RCPD, as per the proposal, but in the LSI region only. In the short term this alternative would have the same effect as the proposal. In the longer term, however, it could avoid creating an incentive for summer demand response in the UNI or USI regions. This might or might not be efficient, depending on the extent to which it allowed deferral of network investment to serve these regions.

- 5.5.6 Transpower has advised that *‘in our assessment excluding the 1 November to 30 April period from the RCPD CMP is unlikely to have any material effect of transmission investment requirements in the UNI, LNI and USI regions in the near term... We conclude that the transmission investment related costs of [the proposal] are likely to be ... non-existent, in relation to the UNI, USI and LNI regions.’* On the basis of this advice, the alternative option of excluding summer trading periods in the LSI region only is likely to be inferior to the proposal.
- 5.5.7 Another option would be to move to a different basis for the interconnection charge, such as a per-MWh or capacity-based charge on load. A per-MWh charge would probably reduce the disincentive to increase production in summer; a capacity-based charge would remove it entirely. However, as set out in Section 4, the Authority tentatively considers that neither of these options is preferable to retaining the RCPD allocation (under the current TPM Guidelines). Therefore they are not considered further in this section.
- 5.5.8 Therefore, the Authority concludes that the proposal is preferable to the alternatives – with the possible exception of the ‘RCPD quantity adjustment provision’ component. Section 7 addresses the question of whether the Authority should proceed with the ‘amended RCPD CMP’ component, the ‘RCPD quantity adjustment provision’ component, or both. These two proposals are not mutually exclusive, but they do both address essentially the same problem.

5.6 Assessment of costs and benefits

- 5.6.1 The main benefit of the proposal is expected to lie in removing the disincentive on NZAS to increase summer production, if it is efficient to do so. As set out in the Authority’s problem definition paper, the productive efficiency benefit of doing so is estimated to be in the range from \$4 million to \$32 million present value.
- 5.6.2 These estimates treat the value-added from incremental aluminium production as the sole source of benefit. It is possible that the proposal may have broader effects. For example, being able to operate viably in summer may reduce the likelihood of wider scale-back or shutdown of operations at the smelter, with its associated costs.
- 5.6.3 The proposed amendment is not expected to cause significant disbenefits. In particular:
- (a) the Authority is not aware of any way in which the amendment could cause inefficient investment in, or operation of, demand response
 - (b) Transpower has indicated that it does not expect the amendment to lead to significant additional transmission investment being required. The Authority notes that summer regional peak demand could drive the need for additional transmission investment at some future time, but considers at this point that

the expected discounted economic cost of such transmission investment is less than the estimated benefit above.

- 5.6.4 The proposed amendment is not expected to have significant transactional costs or benefits.

5.7 Assessment under section 32(1) of the Act

- 5.7.1 Section 32(1) of the Act provides that Code provisions must be consistent with the Authority's objective and be necessary or desirable to promote any or all of the following:

- (a) competition in the electricity industry
- (b) the reliable supply of electricity to consumers
- (c) the efficient operation of the electricity industry
- (d) the performance by the Authority of its functions
- (e) any other matters specifically referred to in the Act as a matter for inclusion in the Code.

- 5.7.2 Table 4 sets out an assessment of the proposed amendment against the requirements of section 32(1) of the Act.

Table 4: How the proposal complies with section 32(1) of the Act

Requirement	Comment
The proposed amendment is consistent with the Authority's objective under section 15 of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.	The proposed amendment is expected to promote efficiency for the long-term benefit of consumers, by removing an inefficient incentive for load parties (especially in the LSI) to decrease summer electricity consumption.
The proposed amendment is necessary or desirable to promote any or all of the following:	
(a) competition in the electricity industry;	The proposed amendment is not expected to affect competition materially.
(b) the reliable supply of electricity to consumers;	The proposed amendment is not expected to affect reliability materially.

(c) the efficient operation of the electricity industry;	The proposed amendment is expected to promote efficiency, by removing an inefficient incentive for load parties (especially in the LSI) to decrease summer electricity consumption
(d) the performance by the Authority of its functions;	The proposed amendment will not materially affect the performance by the Authority of its functions.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendment will not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

5.8 Assessment under the Code amendment principles

5.8.1 Table 5 describes the Authority's consideration of the Code amendment principles in assessing the proposal.

5.8.2 This application of the Code amendment principles in Table 5 evaluates the proposal against the status quo and the alternative options discussed in this section – *with the exception of* the 'amended RCPD CMP' component. The evaluation of the 'amended RCPD CMP' component and the 'RCPD quantity adjustment provision' component against each other is provided in Section 7.

Table 5: Application of Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The proposal provides clearly identified efficiency gains relative to the status quo and the alternative options considered (Section 5.5).
3. Net benefits are quantified	The proposal is expected to provide a net economic benefit, relative to the status quo (Section 5.6).
<i>Because principles 1-3 are satisfied, and the analysis concludes that the proposal is the best option, there is no need to apply principles 4-9.</i>	

- Q12. Do you consider that the proposal in Section 5 (the ‘amended RCPD CMP’ component) is preferable to the status quo and other options discussed in Section 5? If not, please explain your preferred option in terms consistent with the Authority’s statutory objective.**
- Q13. Do you consider that the proposal in Section 5 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?**
- Q14. Do you have any comments on the drafting of the proposal in Section 5, which is included in Appendix B?**

6. Regulatory statement for Transpower's 'RCPD quantity adjustment provision' component

6.1 Transpower's proposal

6.1.1 Transpower's proposal applies when:

- (a) one of Transpower's customers gives notice to Transpower, at least 20 business days before the start of a capacity measurement period, that it proposes to change the amount and/or timing of its electricity offtake in that capacity measurement period, relative to its previous offtake
- (b) the customer requests that Transpower apply an adjustment as below
- (c) Transpower is satisfied that the change in offtake:
 - (i) will affect the incidence of the majority of regional peak demand periods in the relevant region
 - (ii) would not occur, if not for the adjustment as below (*i.e. because the interconnection charge would deter the customer from changing their offtake*)
 - (iii) is unlikely to lead to increased transmission investment.

6.1.2 In this case, Transpower must disregard the change in the customer's offtake for the purposes of identifying regional peak demand periods in the relevant region.

6.1.3 Transpower must also notify the customer, and publish the notice on its website, if it intends to apply the adjustment.

6.2 Impacts on participants

6.2.1 The Authority anticipates that, in the near term, the main participant affected would be NZAS. NZAS could give notice to Transpower that it proposes to increase its summer electricity consumption, and request that Transpower apply an adjustment. If Transpower was satisfied that the conditions were met, it would notify NZAS (and other customers) that it would disregard NZAS's increase in summer electricity consumption when determining LSI regional peak demand periods. This might enable NZAS to increase summer production, if it was economic to do so.

6.2.2 Other participants would not be significantly affected (relative to a status quo scenario in which NZAS did not increase summer production).

6.2.3 It is possible that the proposal could apply to (and therefore affect) other participants. In other words, the proposed amendment is not bespoke – if the

relevant conditions are met another participant could get the benefit of this component.

6.3 The objectives of the proposed amendment

- 6.3.1 The objective of the proposed amendment is to remove an incentive for demand reduction at times, and in locations, where such demand reduction would not help to avoid or defer transmission investment.

6.4 The proposed amendment is expected to meet the objective

- 6.4.1 To the extent that Transpower is able to identify times and locations where increased electricity consumption would not impact on transmission investment requirements, the proposed amendment is expected to meet the objective.

6.5 The Authority has considered other options for addressing the objective, but considers the proposed amendment is preferable

- 6.5.1 Alternative options raised by Transpower include:
- (a) the 'bespoke NZAS' component – i.e. allowing NZAS to increase electricity consumption in the summer months without this being reflected in the calculation of RCPD, up to a point
 - (b) creating a new RCPD region including only the NZAS smelter
 - (c) amalgamating the LSI, LNI and UNI regions into a single RCPD region – so that regional peaks in the 'super-region' would not occur in the summer months
 - (d) the 'amended RCPD CMP' component.
- 6.5.2 For the reasons set out in Section 5, the Authority:
- (a) has not considered the bespoke NZAS component further
 - (b) has not considered further the option of putting the NZAS smelter in its own RCPD region
 - (c) has not considered further the option of creating a single 'super-region'
 - (d) has not considered (*at least, in this section or Section 5*) the option to a different basis for the interconnection charge, such as a per-MWh or capacity-based charge on load.

- 6.5.3 Therefore, the Authority concludes that the proposal is preferable to the alternatives – with the possible exception of the ‘amended ‘RCPD CMP’ component. Section 7 addresses the question of whether the Authority should proceed with the ‘amended RCPD CMP’ component, the ‘RCPD quantity adjustment provision’ component, or both. These two proposals are not mutually exclusive, but they do both address essentially the same problem.

6.6 Assessment of costs and benefits

- 6.6.1 The main benefit of the proposal is expected to lie in removing the disincentive on NZAS to increase summer production, if it is efficient to do so. The scale of this benefit is discussed in Section 5.
- 6.6.2 The proposed amendment is not expected to cause significant disbenefits. In particular:
- (a) the Authority is not aware of any way in which the amendment could cause inefficient investment in, or operation of, demand response
 - (b) providing Transpower correctly identified the circumstances in which increased consumption would not impact on transmission investment requirements, the amendment would not lead to additional transmission investment being required.
- 6.6.3 The proposed amendment is not expected to have significant transactional costs or benefits.

6.7 Assessment under section 32(1) of the Act

- 6.7.1 Section 32(1) of the Act provides that Code provisions must be consistent with the Authority’s objective and be necessary or desirable to promote any or all of the following:
- (a) competition in the electricity industry
 - (b) the reliable supply of electricity to consumers
 - (c) the efficient operation of the electricity industry
 - (d) the performance by the Authority of its functions
 - (e) any other matters specifically referred to in the Act as a matter for inclusion in the Code.
- 6.7.2 Table 6 sets out an assessment of the proposed amendment against the requirements of section 32(1) of the Act.

Table 6: How the proposal complies with section 32(1) of the Act

Requirement	Comment
The proposed amendment is consistent with the Authority's objective under section 15 of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.	The proposed amendment is expected to promote efficiency for the long-term benefit of consumers, by removing inefficient incentives for load parties to decrease electricity consumption (such as in the LSI in summer).
The proposed amendment is necessary or desirable to promote any or all of the following:	
(a) competition in the electricity industry;	The proposed amendment is not expected to affect competition materially.
(b) the reliable supply of electricity to consumers;	The proposed amendment is not expected to affect reliability materially.
(c) the efficient operation of the electricity industry;	The proposed amendment is expected to promote efficiency, by removing inefficient incentives for load parties to decrease electricity consumption (such as in the LSI in summer).
(d) the performance by the Authority of its functions;	The proposed amendment will not materially affect the performance by the Authority of its functions.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendment will not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

6.8 Assessment under the Code amendment principles

- 6.8.1 Table 7 describes the Authority's consideration of the Code amendment principles in assessing the proposal.
- 6.8.2 This application of the Code amendment principles in Table 7 evaluates the proposal against the status quo and the alternative options discussed in this section – *with the exception of* the 'amended 'RCPD CMP' component. The evaluation of the 'amended RCPD CMP' component and the "RCPD quantity adjustment provision' component against each other is provided in Section 7.

Table 7: Application of Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The proposal provides clearly identified efficiency gains relative to the status quo and the alternative options considered (Section 6.5).
3. Net benefits are quantified	The proposal is expected to provide a net economic benefit, relative to the status quo (Section 6.6).
<i>Because principles 1-3 are satisfied, and the analysis concludes that the proposal is the best option, there is no need to apply principles 4-9.</i>	

Q15. Do you consider that the proposal in Section 6 (the ‘RCPD quantity adjustment provision’ component) is preferable to the status quo and other options discussed in Section 6? If not, please explain your preferred option in terms consistent with the Authority’s statutory objective.

Q16. Do you consider that the proposal in Section 6 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?

Q17. Do you have any comments on the drafting of the proposal in Section 6, which is included in Appendix B?

- 7. The relationship between the ‘amended RCPD CMP’ and ‘RCPD quantity adjustment provision’ components**
- 7.1 The two proposals address essentially the same problem, but in different ways**
- 7.1.1 The ‘amended RCPD CMP’ and ‘RCPD quantity adjustment provision’ components, described in Sections 5 and 6 respectively, both address the problem identified in Section 3.2.
- 7.1.2 The Authority anticipates that, in the near term, the two proposals would both enable NZAS to increase summer production, if it is efficient to do so. The main short-term difference would be that, under the ‘RCPD quantity adjustment provision’, LSI regional peak demand periods could still occur in summer (as they sometimes have in the last few years)
- 7.1.3 In the longer term, the two proposals might have different effects:
- (a) under the ‘amended RCPD CMP’ component, summer peaks in all regions would be excluded from the calculation of RCPD indefinitely
 - (b) under the ‘RCPD quantity adjustment provision’ component, there might come a time when NZAS would no longer meet the criteria. On the other hand, there might be other participants, perhaps in other regions, that met the criteria.
- 7.1.4 The two proposals would be implemented differently. The ‘RCPD quantity adjustment provision’ component would require Transpower to assess applications against the criteria, while the ‘amended RCPD CMP’ component would not require on-going decision making.
- 7.1.5 The two proposals are not mutually exclusive. If they were both implemented, then:
- (a) summer peaks would be excluded from the calculation of RCPD
 - (b) Transpower might also disregard offtake changes by a customer for the purpose of determining regional peak demand periods.
- 7.1.6 However, it is feasible that the costs and benefits of the ‘amended RCPD CMP’ component would be affected by the implementation of the ‘RCPD quantity adjustment provision’ component, and vice versa. Accordingly, this section assesses the nature and extent of the potential impact of each proposal on the other.

7.2 Assessment of costs and benefits

7.2.1 Table 8 compares the relative advantages and disadvantages of the two components. It also includes a comparison with the combination of the two components, since they are not mutually exclusive.

Table 8: Comparison between the two components

Feature	'Amended RCPD CMP' component	'RCPD quantity adjustment provision' component	Combination of both components
Near-term effect on the calculation of RCPD for the LSI	Prevent LSI regional peaks from occurring in summer	If NZAS meets the criteria, enable NZAS to increase summer production without affecting the timing of LSI regional peaks	Prevent LSI regional peaks from occurring in summer
Other near-term effects	None	Uncertain – will depend on the application of the provision	Uncertain – will depend on the application of the 'RCPD quantity adjustment provision'
Other longer-term effects	Prevent USI and UNI regional peaks from occurring in summer	Uncertain – will depend on the application of the provision	Combination of effects of both options
Effect on network investment	Could potentially bring forward network investment driven by regional summer peak (if there was any such investment)	Should not affect network investment, if Transpower correctly identifies situations where changes in offtake will not affect investment	As per 'RCPD quantity adjustment provision'
Implementation costs	None	Some transactional costs associated with making an application and applying the criteria	As per 'RCPD quantity adjustment provision'

Feature	'Amended RCPD CMP' component	'RCPD quantity adjustment provision' component	Combination of both components
Durability	Might be changed in future, e.g. because summer peak in some region might drive transmission network investment	Might be changed in future, e.g. because participants sought additional certainty about how their interconnection charges would be calculated	Might be changed in future, e.g. for either of these reasons

7.3 Assessment under the Code amendment principles

7.3.1 Table 9 describes the Authority's consideration of the Code amendment principles in comparing the two proposals.

Table 9: Application of Code amendment principles

Principle	Comment
1. Lawful	Both proposals are lawful, and are consistent with the statutory objective and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	Both proposals provide clearly defined efficiency gains (Sections 5.5 and 6.5).
3. Net benefits are quantified	Each of the two proposals provides an expected net economic benefit relative to the status quo (Sections 5.6 and 6.6). The difference in net economic benefit between the two proposals has not been quantified.

Principle	Comment
<i>Because the assessment of costs and benefits is inconclusive as to which option is preferable, the Authority has applied principles 4-8.</i> <i>If, following consultation, the Authority reached the conclusion that one of the options was preferable to the status quo and alternatives, then it would no longer be necessary to apply principles 4-8.</i>	
4. Preference for small-scale 'trial and error' options	Neither of these components is a small-scale 'trial and error' option. Both would affect multiple participants, and would be difficult to change quickly if they proved unsatisfactory.
5. Preference for greater competition	Neither component is expected to have a material effect on competition.
6. Preference for market solutions	Both components provide for charges to be calculated administratively, rather than through a market.
7. Preference for flexibility to allow innovation	Neither component is specifically designed to promote innovation. However, to the extent that they created incentives for demand response, they would encourage the development of more efficient demand response options in the region(s) concerned.
8. Preference for non-prescriptive options	Both components are prescriptive.

Q18. Having regard to the Code amendment principles, should the Authority proceed with the 'amended RCPD CMP' component, the 'RCPD quantity adjustment provision' component, both or neither?

8. Regulatory statement for Transpower's proposal regarding reverse flows

8.1 Transpower's proposal

- 8.1.1 Transpower's proposal would apply when a customer notified Transpower that a GXP tie⁴² had caused reverse flow⁴³ in the customer's network, and Transpower agreed. Under these circumstances, Transpower must adjust the customer's anytime maximum demand or injection (AMD or AMI),⁴⁴ HAMI, SIMI and/or RCPD to minimise the impact of the distortion created by this reverse flow.

8.2 Impacts on participants

- 8.2.1 Transpower has indicated that it does not expect this proposal to have a significant effect on the distribution of TPM charges. The Authority notes that Transpower already adjusts prices to minimise the impact of reverse flow, using the 'exceptional operating circumstances' provision.

8.3 The objectives of the proposed amendment

- 8.3.1 The primary objective of the proposed amendment is to provide distributors with more certainty about how Transpower will handle the effect of reverse flows on transmission charges.
- 8.3.2 The amendment is also intended to provide other parties, including SI generators and all connected parties, with more certainty.

8.4 The proposed amendment is expected to meet the objectives

- 8.4.1 The proposed amendment makes Transpower's decision-making framework more clear, in that it removes the uncertainty associated with the use of the exceptional operating circumstances provision.

⁴² Defined as a situation in which two or more GXPs are electrically connected by one or more lines that do not form part of the grid.

⁴³ Defined as electricity exiting the grid at a GXP and entering the grid at another GXP as a result of a GXP tie.

⁴⁴ AMD and AMI are used in allocating connection charges between connected parties.

8.5 The Authority has considered other options for addressing the objective, but considers the proposed amendment is preferable

- 8.5.1 One option would be for Transpower to continue managing reverse flow situations using 'exceptional operating circumstances' provisions. The Authority considers that this would provide Transpower's customers with slightly less certainty than under the proposed amendment, over investment timeframes.
- 8.5.2 Another option would be for Transpower to declare that it will *not* alter transmission charges to 'fix' the effect of reverse flows. While this option would provide some certainty, it could have the detrimental effects of
 - (a) causing participants (most likely distributors) to reconfigure their networks where it is inefficient to do so
 - (b) deterring investment in new (most likely distribution) network assets.
- 8.5.3 This option could also raise legal issues for Transpower, in that a general decision not to address reverse flows in the way permitted by clause 34(2) of the TPM would fetter Transpower's discretion under that clause.
- 8.5.4 Another option would be to replace the interconnection charge with a capacity charge on load. The capacity charge would not be affected by reverse flows or any other aspect of operation of the grid. However, as set out in Section 4, the Authority considers that the current interconnection charge is preferable to a capacity charge on load (in the absence of more preferred charges under the Authority's TPM decision-making and economic framework – i.e., in decreasing order of preference, a market, market-like, exacerbrators-pay or beneficiaries-pay charge).
- 8.5.5 The Authority concludes that the proposal is preferable to the alternatives.

8.6 Assessment of costs and benefits

- 8.6.1 The benefit of the investment is expected to lie in more efficient investment in, and operation of, transmission customers' networks – especially distribution networks.
- 8.6.2 These benefits have not been quantified.
- 8.6.3 The Authority does not consider that the expected benefit is very large, given that reverse flows can already be resolved under the 'exceptional operating circumstances' provision. However the expected benefit is probably greater than zero.

- 8.6.4 The proposed amendment is not expected to cause significant disbenefits. In particular, the Authority is not aware of any way in which it could cause inefficient investment in, or operation of, networks.
- 8.6.5 The proposed amendment is not expected to have significant transactional costs or benefits.

8.7 Assessment under section 32(1) of the Act

- 8.7.1 Section 32(1) of the Act provides that Code provisions must be consistent with the Authority's objective and be necessary or desirable to promote any or all of the following:
- (a) competition in the electricity industry
 - (b) the reliable supply of electricity to consumers
 - (c) the efficient operation of the electricity industry
 - (d) the performance by the Authority of its functions
 - (e) any other matters specifically referred to in the Act as a matter for inclusion in the Code.
- 8.7.2 Table 10 sets out an assessment of the proposed amendment against the requirements of section 32(1) of the Act.

Table 10: How the proposal complies with section 32(1) of the Act

Requirement	Comment
The proposed amendment is consistent with the Authority's objective under section 15 of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.	The proposed amendment is expected to promote efficiency for the long-term benefit of consumers, by supporting efficient investment in, and operation of, Transpower's customers' networks.
The proposed amendment is necessary or desirable to promote any or all of the following:	
(a) competition in the electricity industry;	The proposed amendment is not expected to materially affect competition.

(b) the reliable supply of electricity to consumers;	To the extent the proposal promotes efficient investment in customers' networks, particularly distribution, it would promote reliability.
(c) the efficient operation of the electricity industry;	The proposed amendment is expected to promote efficiency, by promoting efficient investment in, and operation of, Transpower's customers' networks.
(d) the performance by the Authority of its functions;	The proposed amendment will not materially affect the performance by the Authority of its functions.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendment will not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

8.8 Assessment under the Code amendment principles

8.8.1 Table 11 describes the Authority's consideration of the Code amendment principles in assessing the proposal.

Table 11: Application of Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The proposal appears to provide defined efficiency gains but these have not been quantified.

Principle	Comment
3. Net benefits are quantified	No - net benefits are not quantified, because: - the Authority does not know how likely it is that Transpower's customers might carry out inefficient investment, if the proposal did not proceed - if such inefficient investment occurred, the Authority does not know what economic costs might be incurred as a result. As set out in Section 8.6, the Authority considers that the net benefit of the proposal would be small in magnitude, but probably positive.
<i>Because principles 1 and 2 are satisfied, and the analysis concludes that the proposal is the best option, there is no need to apply principles 4-9.</i>	

Q19. Do you consider that the proposal in Section 8 (regarding reverse flows) is preferable to the status quo and other options? If not, please explain your preferred option in terms consistent with the Authority's statutory objective. Q20. Do you consider that the proposal in Section 8 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed? Q21. Do you have any comments on the drafting of the proposal in Section 8, which is included in Appendix B?
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Glossary of abbreviations and terms

ACOT	Avoided cost of transmission – payments made to embedded generators by some distributors, reflecting the embedded generator's effect of lowering the transmission charges incurred by the distributor
Act	Electricity Industry Act 2010
AMD, AMI	Anytime maximum demand and injection – used in allocating connection charges between connected parties
'Amended RCPD CMP' component	Transpower's proposal to exclude summer trading periods from the calculation of RCPD in all four RCPD regions
Authority	Electricity Authority
'Bespoke NZAS' component	Transpower's proposal to treat, for the purpose of the interconnection charge, NZAS loads between 572-636 MW as if they were just 572 MW, during the period from Nov to Apr
CMP	Capacity measurement period – a period of time used to calculate transmission charges for subsequent pricing years
Code	Electricity Industry Participation Code 2010
Connection charge	The component of the TPM that recovers the costs of providing connection services
HAMI	Historical anytime maximum injection – the allocator currently used in the HVDC charge
HVDC charge	The component of the TPM that recovers the costs of the high voltage direct current inter-island link
Interconnection charge	The component of the TPM that recovers all TPM costs not recovered through the HVDC charge or connection charge
LNI, LSI	Lower North Island and Lower South Island – two of the four regions used in the calculation of the RCPD allocator of the interconnection charge
MAR	Maximum allowable revenue – the amount of money that Transpower can recover for its regulated services
N	The number of regional coincident peaks used in the calculation of the RCPD allocator of the interconnection charge – currently 12 for UNI and USI, 100 for LNI and LSI
NZAS	New Zealand Aluminium Smelters Ltd
RCPD	Regional coincident peak demand – the allocator used in the interconnection charge

'RCPD quantity adjustment provision' component	Transpower's proposal to require Transpower to disregard customer's offtake changes in a region for the purpose of determining regional peak demand periods, in cases where a change in the customer's offtake would alter the incidence of a majority of peaks in the region, would not impact on transmission investment requirements, and would not occur in the absence of the adjustment for the change
SIMI	South Island mean injection – the proposed new allocator to be used for the HVDC charge
TPM	Transmission pricing methodology
UNI, USI	Upper North Island and Upper South Island – see LNI

Appendix A Format for submissions

Question	Comment
Q1. Do you have any comments on the part of the problem definition that relates to the interconnection charge incentivising a higher level of demand response than is efficient?	
Q2. Do you have any comments on the part of the problem definition that relates to the RCPD allocation deterring some consumers from increasing consumption in the summer months?	
Q3. Do you have any comments on the part of the problem definition that relates to the treatment of reverse flows?	
Q4. In your view, how would participants change their behaviour if the RCPD allocation used N=100 in the UNI and USI regions? What would be the economic costs and benefits of this change in behaviour?	
Q5. In your view, how would participants change their behaviour if the RCPD allocation used N=500 in all four regions? What would be the economic costs and benefits of this change in behaviour?	
Q6. In your view, how would participants change their behaviour if the interconnection charge was a per-MWh charge on gross load? What would be the economic costs and benefits of this change in behaviour?	
Q7. In your view, how would participants change their behaviour if the interconnection charge was a 50-50 mix of the status quo and a per MWh charge on gross load? What would be the economic costs and benefits of this change in behaviour?	
Q8. In your view, how would participants change their behaviour if the interconnection charge was a combination of a regional LRMC-based charge and a per-MWh charge on gross load? What would be the economic costs and benefits of this change in behaviour?	

Q9. Do you consider that the proposal in Section 4 (i.e. that the RCPD allocation should use N=100 for all four regions) is preferable to the status quo and other options? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.	
Q10. Do you consider that the proposal in Section 4 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?	
Q11. Do you have any comments on the drafting of the proposal in Section 4, which is included in Appendix B?	
Q12. Do you consider that the proposal in Section 5 (the 'amended RCPD CMP' component) is preferable to the status quo and other options discussed in Section 5? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.	
Q13. Do you consider that the proposal in Section 5 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?	
Q14. Do you have any comments on the drafting of the proposal in Section 5, which is included in Appendix B?	
Q15. Do you consider that the proposal in Section 6 (the 'RCPD quantity adjustment provision' component) is preferable to the status quo and other options discussed in Section 6? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.	
Q16. Do you consider that the proposal in Section 6 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?	
Q17. Do you have any comments on the drafting of the proposal in Section 6, which is included in Appendix B?	

Q18. Having regard to the Code amendment principles, should the Authority proceed with the 'amended RCPD CMP' component, the 'RCPD quantity adjustment provision' component, both or neither?	
Q19. Do you consider that the proposal in Section 8 (regarding reverse flows) is preferable to the status quo and other options? If not, please explain your preferred option in terms consistent with the Authority's statutory objective.	
Q20. Do you consider that the proposal in Section 8 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?	
Q21. Do you have any comments on the drafting of the proposal in Section 8, which is included in Appendix B?	

Appendix B Proposed Code amendments to implement components

Schedule 12.4

Transmission Pricing Methodology

cl 12.84

1 Introduction

The **transmission pricing methodology** is used to recover the full economic costs of **Transpower's** services, with the exception of investment contracts entered into under clauses 12.70 and 12.71 of this Code, existing new investment contracts and other contracts of the kind referred to in clause 12.95 of this Code. The full economic costs of **Transpower's** services include costs relating to investments which are not subject to approval by the Commerce Commission under section 54R of the Commerce Act 1986 or to which the input methodology under section 54S of that Act applies.

Compare: Electricity Governance Rules 2003 clause 1 schedule F5 part F

2 Overview of the Pricing Methodology—

- (1) **Transpower's** principal objective as a State Owned Enterprise is to operate as a successful business. To this end **Transpower's** pricing must, subject to Part 4 of the Commerce Act 1986, recover the costs of providing its transmission services, which include capital, maintenance, operating and overhead costs. Before the start of each **pricing year**, **Transpower's** Board approves forecasts of—
 - (a) the revenue required to recover the costs of providing AC transmission services during the **pricing year**. This forecast is referred to as the **AC revenue** for that **pricing year**; and
 - (b) the revenue required to recover the costs of providing the **HVDC assets** during the **pricing year**. This forecast is referred to as the **HVDC revenue** for that **pricing year**.
- (2) The **transmission pricing methodology** comprises—
 - (a) **connection** charges, which recover part of **Transpower's AC revenue** by reference to the cost of providing **connection assets**. Clauses 8 to 26 describe how **connection** charges are calculated;
 - (b) interconnection charges, which recover the remainder of **Transpower's AC revenue**. Clauses 27 to 30 describe how interconnection charges are calculated; and
 - (c) HVDC charges, which recover **Transpower's HVDC revenue**. Clauses 31 to 33 describe how HVDC charges are calculated.
- (3) An overview of how **Transpower's AC revenue** and **HVDC revenue** are recovered through these charges is shown in diagrammatic form in Appendix A.
- (4) The **transmission pricing methodology** also describes—
 - (a) how the costs of **transmission alternative** services are charged and recovered, if and when **transmission alternatives services** are provided and/or funded by **Transpower** (clause 35); and

- (b) practical ways to facilitate greater transparency in relation to **Transpower's** prudent discount policy, which helps to ensure that the **transmission pricing methodology** does not provide incentives for inefficient by-pass of the existing grid (clauses 36 to 42).

Compare: Electricity Governance Rules 2003 clause 2 schedule F5 part F

Clause 2(2)(a): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

3 Definitions and interpretation

Unless the context otherwise requires—

AC asset means a **grid asset** other than an **HVDC asset**

AC revenue has the meaning set out in clause 2(1)

AC switch means a switch that is an **AC asset**

alternative project means an investment proposed by a **customer**, which if implemented, would bypass existing **grid assets**, but does not include proposed new generation

annual charges means any or all of the **annual connection charge**, **annual interconnection charge** and **annual HVDC charge** for a **customer** at a **connection location** for a **pricing year**

Schedule 12.4, clause 3, **annual charges**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

annual connection charge has the meaning set out in clause 8(2)

annual HVDC charge has the meaning set out in clause 31

annual interconnection charge has the meaning set out in clause 27

anytime maximum demand or **AMD** for a **customer** at a **connection location** means the average of the 12 highest **offtake** quantities for that **customer** at that **connection location** during the **capacity measurement period** for the relevant **pricing year**. This definition is subject to clause 34 of this **transmission pricing methodology** and any prudent discount agreement

anytime maximum injection or **AMI** for a **customer** at a **connection location** means the average of the 12 highest **injection** quantities for that **customer** at that **connection location** during the **capacity measurement period** for the relevant **pricing year**. This definition is subject to clause 34 of this **transmission pricing methodology** and any prudent discount agreement

capacity measurement period means, for ~~any~~ **pricing year**—

(a) for every purpose other than determining **regional peak demand periods**, the 12 month period ~~commencing starting~~ 1 September and ending ~~with the close of~~ 31 August ~~inclusive~~, immediately before the commencement of the **pricing year**;

(b) for the purpose of determining **regional peak demand periods**, the period specified in paragraph (a), excluding within that period the period commencing 1 November and ending with the close of 30 April immediately before the commencement of the **pricing year**

connection asset has the meaning set out in clause 6(1)

connection link has the meaning set out in clause 5(c)

connection location means the **substation** or other location at which a **customer's assets** are directly **connected** to the **grid**

Schedule 12.4, clause 3, **connection location**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

connection node has the meaning set out in clause 5(b)

customer means a person who has or controls **assets** directly **connected** to the **grid** and, in relation to a **connection location**, means a person who has or controls **assets** directly **connected** to the **grid** at that **connection location**. A **customer** may be both an **offtake customer** and an **injection customer** at the same **connection location**

Schedule 12.4, clause 3, **customer**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

customer allocation has the meaning set out in clause 25(1)

financial year means the financial year adopted by **Transpower** from time to time, being a 12 month period or such other period as **Transpower** determines. **Transpower's** current financial year is a 12 month period from 1 July to 30 June

grid assets means assets and other works (including **land and buildings**) owned or operated by **Transpower**, which form part of the **grid** or are required to support the **grid**

GXP tie means a situation in which 2 or more **GXPs** are electrically connected by 1 or more **lines** that do not form part of the **grid**

historical anytime maximum injection or **HAMI** for a **customer** at a **South Island generation connection location** means either the average of the 12 highest injections at that **South Island generation connection location** during the **capacity measurement period** for the relevant **pricing year**; or the average of the 12 highest **injections** at that **South Island generation connection location** during any of the four immediately preceding **pricing years**, whichever is highest. This definition is subject to clause 34 of this **transmission pricing methodology** and any prudent discount agreement

HVDC assets means the **HVDC link** and all **land and buildings** associated with the **HVDC link**

HVDC customer means a **customer** who is, from time to time, the owner or operator of—

- (a) **South Island generation** which is directly **connected** to the **grid assets**; or
- (b) a **local network** to which **South Island generation** is **connected**, either directly or indirectly;

Schedule 12.4, clause 3, **HVDC customer**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

HVDC revenue has the meaning set out in clause 2(1)

independent expert means an independent person who is a recognised technical expert in the matter that has been referred to him or her. In appointing an **independent expert** the party referring the matter to the **independent expert** must nominate 3 persons and the other party may agree that any one of them be appointed. Failing agreement between the parties, the **independent expert** will be appointed by the **Authority**

injection means the net quantity of **electricity** flow into the **grid** at a **connection location** from a **customer's assets** during a **half hour** determined from **metering information**. This definition is subject to clause 34 of this **transmission pricing methodology** and any prudent discount agreement

injection customer means, subject to clause 34, in relation to a **connection location**, a **customer** who has or controls assets from which electricity flowed into the **grid** at that **connection location** in any **half hour** during the **capacity measurement period** for the relevant **pricing year** or, if the **connection location** is a **South Island generation connection location**, an **HVDC customer** who has or controls assets from which electricity flowed into the **grid** at the **South Island generation connection location** in any **half hour** during the **capacity measurement period** for the relevant **pricing year** or a **capacity measurement period** for any of the 4 immediately preceding **capacity measurement periods**

interconnection asset has the meaning set out in clause 6(2)

interconnection link has the meaning set out in clause 5(d)

interconnection node has the meaning set out in clause 5(a)

land and buildings means any and all land or interest in land (including easements) acquired by **Transpower** for the purposes of establishing a **connection location** or **substation**, or for supporting **grid assets**, together with all buildings, oil containment facilities and the capitalised cost of establishing a **connection location** or **substation** or other **grid asset** (as the case may be)

link has the meaning set out in clause 4(3)

monthly charges means any or all of the **monthly connection charge**, **monthly interconnection charge** and **monthly HVDC charge** for a **customer** at a **connection location**

monthly connection charge has the meaning set out in clause 8(2)

monthly HVDC charge has the meaning set out in clause 31

monthly interconnection charge has the meaning set out in clause 27

new investment contract means a contract entered into at any time between **Transpower** and a **customer** of **Transpower**, under which **Transpower** agrees to provide any new or upgraded **grid assets** and the **customer** agrees to pay charges based on **Transpower's** cost of providing the new or upgraded **grid assets**. It includes, but is not limited to a **new investment agreement contract** as defined in Part 1 of this Code

node has the meaning set out in clause 4(1)

offtake means the net quantity of **electricity** flow out of the **grid** at a **connection location** into **customer assets** during a **half hour** determined from **metering information**. This definition is subject to clause 34 of this transmission pricing methodology and any prudent discount agreement

offtake customer means, subject to clause 34, in relation to a **connection location**, a **customer** who has or controls assets into which electricity flowed from the **grid** at that **connection location** in any **half hour** during the **capacity measurement period** for the relevant **pricing year**

optimised replacement cost means, for any assets or group of assets, the optimised replacement cost of that asset or group of assets recorded in a Transpower asset register as at the **transition date**

point of injection means a **connection location** at which an **injection customer** has assets **connected** to the **grid**

Schedule 12.4, clause 3, **point of injection**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

pricing year means the period from April 1 to March 31, in respect of which **Transpower** calculates its prices

region means a group of **connection locations**, being one of the groups described identified in Appendix B as—

- (a) Upper North Island; and
- (b) Lower North Island; and
- (c) Upper South Island; and
- (d) Lower South Island;

regional coincident peak demand or **RCPD** for a **customer** at a **connection location** means the **customer's offtake** at that **connection location** during a **regional peak demand period**. This definition is subject to clause 34 of this **transmission pricing methodology** and any prudent discount agreement

Clause 3 **regional coincident peak demand**: inserted, on 15 May 2014, by clause 34(b) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

regional demand means, in any **half hour**, the sum over all **customers** at all **connection locations** in a **region** of all **offtake** quantities at those **connection locations**

regional peak demand period means, ÷ for each region,

(a)—in relation to the Upper North Island and the Upper South Island regions, a half hour in which any of the 12 highest regional demands occurs during the capacity measurement period for the relevant pricing year; and

~~(b) in relation to the Lower North Island and the Lower South Island regions,~~ a half hour in which any of the 100 highest **regional demands** occur during a **capacity measurement period** for the relevant **pricing year**.

This definition is subject to clause 34 of this **transmission pricing methodology** and any prudent discount agreement

regional coincident peak *[Revoked]*

Clause 3 **regional coincident peak**: revoked, on 15 May 2014, by clause 34(a) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

replacement cost means—

- (a) for a **connection asset** commissioned before the **transition date**, the cost of replacing that asset (either separately or as part of a group of assets) with a modern equivalent asset with the same service potential, multiplied by the **replacement cost adjustment factor**; and
- (b) for any other **grid asset**, the cost of replacing that asset (either separately or as part of a group of assets) with a modern equivalent asset with the same service potential,

as determined by **Transpower** and (unless stated otherwise) recorded in a **Transpower** asset register;

replacement cost adjustment factor means for any asset (or group of assets) the percentage which is the **optimised replacement cost** divided by the cost, as at (or about) the **transition date**, of replacing that asset (or group of assets) with the then modern equivalent asset with the same service potential

reverse flow means electricity exiting the **grid** at a **GXP** and entering the **grid** at another **GXP** as a result of a **GXP tie**

South Island generation means, subject to clause 34, any **generating unit** or **generating station** located in the South Island, which:

- (a) is directly **connected** to the **grid** or is **connected** to a **local network** which is **connected** (directly or indirectly) to the **grid**; and
- (b) has (directly or indirectly) injected electricity into the **grid** at any time during any **capacity measurement period** for the previous 5 **pricing years**

Schedule 12.4, clause 3, **South Island generation**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

South Island generation connection location means any **connection location** at which **South Island generation** is **connected** to the **grid** either directly, or indirectly via **connection** of a **local network**, to which **South Island generation** is in turn either directly or indirectly **connected** **substation** means a substation, including all **land and buildings**, switches, transformers, revenue meters and all other assets comprising or located at that substation

Schedule 12.4, clause 3, **South Island generation connection location**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

weighted average cost of capital means, for any **pricing year**, the pre-tax nominal weighted average cost of capital used by **Transpower** to determine **AC revenue** or **HVDC revenue** (as the case may be) for that **pricing year**.

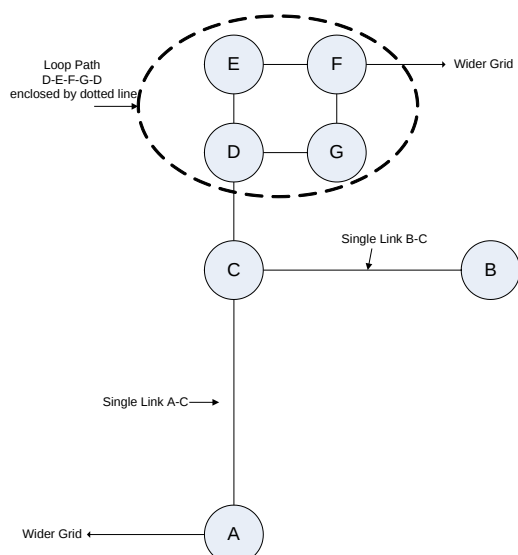
Compare: Electricity Governance Rules 2003 clauses 3.1 to 3.53 schedule F5 part F

- (1) A **node** is any of the following:
 - (a) a **connection location**:
 - (b) a location where a circuit, which is **connected** to 2 or more other **nodes**, diverges or terminates (such as a “tee” point or a deviation):
 - (c) any **substation** or switching station.
- (2) Any **node** which connects with 1 or more multiple circuits on the same towers or poles where at least 1 of those circuits deviates or terminates at that **node** is treated as a single **node** encompassing all of those circuits at that location.

The diagram illustrates the definition of a node at location C. It shows a vertical line of towers with nodes A, B, C, D, E, F, and G. Node C is highlighted with a dashed circle. Labels indicate "Double Circuit Line on same towers" and "Wider Grid".

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Figure 2 – Illustration of links and loop path



Compare: Electricity Governance Rules 2003 clauses 3.54 to 3.57 schedule F5 part F

Clause 4(1)(b): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

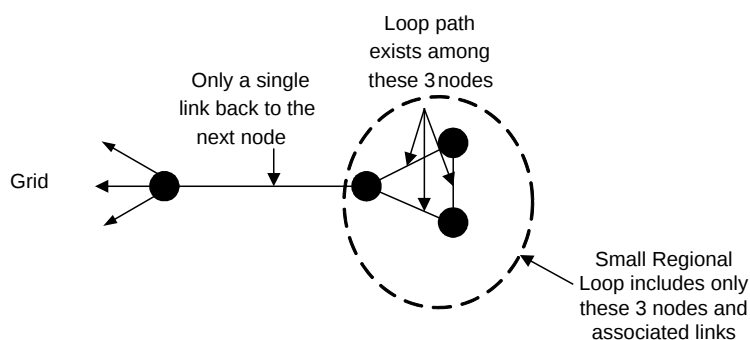
Clause 4(3): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

5 Identification of Nodes and Links as Connection or Interconnection

Nodes and **links** are identified as **connection nodes** or **connection links** or **interconnection nodes** or **interconnection links** according to the following rules:

- an **interconnection node** is any **node connected** to 2 or more **nodes** in a “loop”, other than a “small regional loop”. A loop is a continuous path of **nodes** and **links** with the same start and end **node**. A “small regional loop” is where a loop path exists between any group of **nodes** (excluding the **nodes** at Benmore and Haywards) with only a single **link** from the loop back to the next **node** that is outside the loop (see Figure 3 below):
- a **connection node** is any **node** that is not an **interconnection node**:

Figure 3 – Example of a small regional loop



- (c) a **connection link** is a **link** with a **connection node** at one or more of its ends;
- (d) an **interconnection link** is a **link** that connects 2 **interconnection nodes**;
- (e) **links** and **nodes** that comprise a “small regional loop” are **connection links** and **connection nodes**.

Compare: Electricity Governance Rules 2003 clause 3.58 schedule F5 part F

Clause 5(a): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

6 Definition of Connection Assets and Interconnection Assets

(1) A **connection asset** is—

- (a) any **grid asset** at a **connection node** other than **voltage support** equipment that is for **grid voltage support** purposes and has not been installed at a **customer's** request; and
- (b) at an **interconnection node** that is a **connection location**,—
 - (i) any **grid asset** that is specifically required to **connect** a **customer**, including a supply transformer, feeder bay or supply transformer high voltage or low voltage breaker. Low voltage breakers, low voltage bus section breakers, voltage transformers, revenue meters and other equipment where they are on the same bus as the feeders are also **connection assets**; and
 - (ii) any **grid asset** that is used both to **connect** a **customer** (whether injection or offtake) and for **grid** operation generally; and
 - (iii) a proportion of the **land and buildings** at that **connection location**. The proportion of **land and buildings** defined as a **connection asset** is that proportion which the **replacement cost** of the **connection assets** identified in subparagraph (i) but excluding **land and buildings**, bears to the **replacement cost** of all **grid assets** (excluding **land and buildings**) at the **connection location**; and
- (c) any **grid asset** that is a **connection link**. A single line, recorded as such in a **Transpower** asset register, may form part of more than 1 **link**, so that a portion of a line may be identified as a **connection asset** with the remaining portion identified as an **interconnection asset**. For example, in Figure 1, if a line AB were recorded in a **Transpower** asset register, it would form part of a **connection link** BC and an **interconnection link** AC. If part of a line is, or forms part of, a **connection link**, the value and costs ascribed to the **connection link** for the purposes of calculating **connection** charges is the same proportion that the ratio of the length of the **connection link** bears to the total length of the line.

(2) An **interconnection asset** is any **grid asset** that is not a **connection asset**, or an **HVDC asset**.

(3) A **connection asset** which connects a **customer's assets** at a **connection location** to the **interconnection assets** is referred to as a **connection asset** "for" or "which connects" (or other grammatical form of that phrase) that **connection location** or **customer's assets** (as the case may be).

Compare: Electricity Governance Rules 2003 clauses 3.59 to 3.61 schedule F5 part F

Clause 6(1)(b)(i) and (ii): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 6(1)(c): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

7 Interpretation

Unless the context otherwise requires—

- (a) all defined terms are shown in bold text; and
- (b) terms defined in Part 1 of this Code have that defined meaning;
- (c) terms defined below and elsewhere in the text of this **transmission pricing methodology** take that defined meaning, and any other grammatical form of that term has a corresponding meaning; and
- (d) if there is any inconsistency between the text description of a calculation for which there is formula and the particular formula, the formula takes precedence; and
- (e) diagrams are for information only and do not form a binding part of this **transmission pricing methodology**; and
- (f) a reference—
 - (i) to the singular includes the plural and conversely; and
 - (ii) to a person includes an individual, company, other body corporate, association, partnership, firm, joint venture, trust or Government agency; and
- (g) the word "including" is to be read as "including, but not limited to", and the word "includes" is to be read as "includes, without limitation"; and
- (h) if any matter is to be determined by **Transpower** or **Transpower's** Board, it is to be determined in **Transpower's** or **Transpower's** Board (as the case may be) sole discretion while acting at all times reasonably; and
- (i) a reference to a preceding **financial year** is a reference to the first complete **financial year** that precedes the start of the **pricing year** in respect of which the relevant calculation is undertaken; and
- (j) a reference to a prudent discount agreement includes any agreement entered into under the prudent discount policy in clauses 36 to 42 and any agreement which has the same or similar purpose as the prudent discount policy (including a **notional embedding contract**) entered into between **Transpower** and a **customer** whether before or after commencement of this **transmission pricing methodology**.

Compare: Electricity Governance Rules 2003 clauses 3.62 to 3.71 schedule F5 part F

Connection Charges

8 Calculation of the Connection Charges

- (1) A **connection** charge for each **connection asset** for a **connection location** is calculated for each **pricing year** for each **customer** at that **connection location** by multiplying the sum of the asset, maintenance, operating and (for **injection customers**) overhead cost components for a **connection asset** by the relevant **customer allocation**, as follows:

$$\text{connection charge} = (A_{\text{conn}} + M_{\text{conn}} + O_{\text{conn}} + IO_{\text{conn}}) \times CA_{\text{conn}}$$

where

A_{conn} is the asset component for the **connection asset** calculated in accordance with clauses 10 to 12

M_{conn} is the maintenance component for the **connection asset** calculated in accordance with clauses 13 to 17 and is $M_{\text{conn subs}}$ or $M_{\text{conn line type}}$ depending on the nature of the **connection asset**

O_{conn} is the operating component for the **connection asset** calculated in accordance with clauses 18 to 20

IO_{conn} is the injection overhead component for the **connection asset** calculated in accordance with clauses 21 to 24

CA_{conn} is the customer allocation for the **connection asset** for the **connection location** in respect of which the **connection charge** is being calculated, calculated in accordance with clause 25(1) and (2)(a) to (c).

- (2) The sum of all **connection charges** calculated for a **customer** for all **connection assets** for a **connection location** in accordance with subclause (1) is the **annual connection charge** for that **customer** at that **connection location** in that **pricing year**. The **customer's monthly connection charge** at that **connection location** for that **pricing year** is (subject to clause 34 of this **transmission pricing methodology**) calculated as 1/12 of the **annual connection charge**. The example **connection charge** report at clause ~~25(3)~~25(2)(d) illustrates how a **customer's annual connection charge** for a **connection location** is calculated.
- (3) If a **customer** is both an **offtake customer** and an **injection customer** at a **connection location**, **connection charges** for that **connection location** are calculated separately for that **customer** as an **offtake customer** and an **injection customer**.

Compare: Electricity Governance Rules 2003 clauses 4.1 to 4.3 schedule F5 part F

Clause 8: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

9 Calculation of Connection Charge Components

- (1) Each of the asset, maintenance, operating and overhead cost components of the **connection charge** is calculated by reference to a rate set for that component which is then applied to the particular **connection asset**. Different rates may be set for different types of **connection assets**; for example, different rates are used to calculate the **maintenance component** depending on whether the **connection asset** is located at a **substation** or is a line. Different types of lines have different rates. Clauses 10 to 26 describe how the rates are set and applied to determine each component of the **connection charge**.

- (2) The rates for each component of the **connection** charge are recalculated for each **pricing year**.

Compare: Electricity Governance Rules 2003 clauses 4.4 and 4.5 schedule F5 part F

Clause 9: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

10 Asset Component

The asset component of the **connection** charge allocates a portion of the cost of funding all **connection assets** plus their depreciation to the **connection asset** for which the **connection** charge is being calculated.

Compare: Electricity Governance Rules 2003 clause 4.6 schedule F5 part F

Clause 10: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

11 Asset Return Rate

The asset return rate used to calculate the asset component is referred to as **ARR_{conn}** and is expressed as a proportion. **ARR_{conn}** is calculated by dividing the product of the **weighted average cost of capital** and the regulatory asset value of all **connection assets** plus the annual depreciation of those assets by the **replacement cost** of all **connection assets** as follows:

$$ARR_{conn} = \frac{WACC \times RAV_{conn} + D_{conn}}{\sum_{conn} RC_{conn}}$$

where

WACC is the **weighted average cost of capital** (expressed as a percentage)

RAV_{conn} is the regulatory asset value of all **connection assets**, as determined by **Transpower** and recorded in a **Transpower** asset register (expressed in dollars)

D_{conn} is total annual depreciation of all **connection assets** in the preceding **financial year** as determined by **Transpower** and recorded in a **Transpower** asset register (expressed in dollars)

$\sum_{conn} RC_{conn}$ is the total **replacement cost** of all **connection assets**.

Compare: Electricity Governance Rules 2003 clause 4.7 schedule F5 part F

12 Calculation of Asset Component

The **asset component** of a **connection** charge is calculated by multiplying **ARR_{conn}** by the **replacement cost** of the **connection asset** for which the **connection** charge is being calculated as follows:

$$A_{\text{conn}} = \text{ARR}_{\text{conn}} \times \text{RC}_{\text{conn}}$$

where

RC_{conn} is the **replacement cost** of the **connection asset** for which the **connection charge** is being calculated (expressed in dollars).

Compare: Electricity Governance Rules 2003 clause 4.8 schedule F5 part F

Clause 12: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

13 Maintenance component

- (1) The maintenance component of the **connection charge** allocates a portion of **Transpower's** total maintenance costs for all **connection assets** to the **connection asset** for which the **connection charge** is being calculated.
- (2) Maintenance recovery rates are set separately for **connection assets** located at **substations** and for the different types of lines. The different line types (all AC) used are—
 - (a) 220kV or higher voltage tower lines;
 - (b) other tower lines; and
 - (c) pole lines.

Compare: Electricity Governance Rules 2003 clauses 4.9 and 4.10 schedule F5 part F

Clause 13(1): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

14 Substation Maintenance Recovery Rate

The maintenance recovery rate used to calculate the maintenance component of the **connection charge** for **connection assets** located at **substations** is referred to as $\text{MRR}_{\text{conn subs}}$ and is expressed as a proportion. $\text{MRR}_{\text{conn subs}}$ is calculated as the average of the annual maintenance costs incurred by **Transpower** for all **connection assets** located at all **substations** in each of the 4 immediately preceding **financial years** divided by the sum of the **replacement costs** of all **connection assets** located at all **substations** as follows:

$$\text{MRR}_{\text{conn subs}} = \frac{\text{MC}_{\text{conn subs}}}{\sum_{\text{subs conn}} \text{RC}_{\text{conn subs}}}$$

where

$\text{MC}_{\text{conn subs}}$ is the average of the annual maintenance costs incurred by **Transpower** for all **connection assets** located at all **substations** in each of the 4 immediately preceding **financial years**, as determined by **Transpower** and recorded in **Transpower's** Maintenance Management System accounts for each of those **financial years** (expressed in dollars)

$\sum_{\text{subs}} \sum_{\text{conn}} RC_{\text{conn subs}}$ is the sum of the **replacement costs** of all **connection assets** located at all **substations**.

Compare: Electricity Governance Rules 2003 clause 4.11 schedule F5 part F

Clause 14: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

15 Calculation of Maintenance Component for a Connection Asset Located at a Substation

The maintenance component of the **connection** charge for a **connection asset** located at a **substation** is calculated by multiplying $MRR_{\text{conn subs}}$ by the **replacement cost** of the **connection asset** for which the **connection** charge is being calculated as follows:

$$M_{\text{conn subs}} = MRR_{\text{conn subs}} \times RC_{\text{conn subs}}$$

where

$RC_{\text{conn subs}}$ is the **replacement cost** of the **connection asset** for which the **connection** charge is being calculated (expressed in dollars).

Compare: Electricity Governance Rules 2003 clause 4.12 schedule F5 part F

Clause 15: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

16 Line Maintenance Recovery Rate

The maintenance recovery rate used to calculate the maintenance component of the **connection** charge for **connection assets** which are lines is referred to as $MRR_{\text{conn line type}}$ and is expressed as a dollar cost per length (expressed in km) of line for each line type. $MRR_{\text{conn line type}}$ is calculated for each of the 3 types of line referred to in clause 13(2) and is the average of annual maintenance costs incurred by **Transpower** for all lines of the type for which $MRR_{\text{conn line type}}$ is being calculated in each of the preceding 4 **financial years** divided by the total line length of line of that type as follows:

$$MRR_{\text{conn line type}} = \frac{1}{4} \sum_{n=1}^4 \frac{MC_{\text{conn line type } n}}{TL_{\text{conn line type } n}}$$

where

$MC_{\text{conn line type } n}$ is the average of the annual maintenance costs incurred by **Transpower** for all lines of the type for which the maintenance recovery rate is being calculated in each of the 4 immediately preceding **financial years**, as determined by **Transpower** and recorded in **Transpower's** Maintenance Management System accounts for each of those **financial years** (expressed in dollars)

$TL_{\text{conn line type } n}$ is the total length of line of the type for which the maintenance recovery rate is being calculated forming part of the **grid assets**

(other than **HVDC assets**), as determined by **Transpower** and recorded in a **Transpower** asset register at the end of the immediately preceding **financial year** (expressed in km).

Compare: Electricity Governance Rules 2003 clause 4.13 schedule F5 part F

Clause 16: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

17 Calculation of the Maintenance Component for Line Connection Assets

The maintenance component of the **connection** charge for a **connection asset** which is a line is calculated by multiplying $MRR_{\text{conn line type}}$ by the length of the line which is the **connection asset** for which the **connection** charge is being calculated as follows:

$$M_{\text{conn line type}} = MRR_{\text{conn line type}} \times L_{\text{conn line}}$$

where

$L_{\text{conn line}}$ is the length of the line which is the **connection asset** for which the **connection** charge is being calculated, as determined by **Transpower** and recorded in a **Transpower** asset register (expressed in km).

Compare: Electricity Governance Rules 2003 clause 4.14 schedule F5 part F

Clause 17: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

18 Operating Component

The operating component of the **connection** charge allocates a portion of **Transpower's** total operating cost for all **AC assets** to the **connection asset** for which the **connection** charge is being calculated.

Compare: Electricity Governance Rules 2003 clause 4.15 Schedule F5 part F

Clause 18: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

19 Operating Recovery Rate

The operating recovery rate used to calculate the operating component of the **connection** charge is referred to as **ORR** and is expressed as a dollar cost per switch. **ORR** is calculated by dividing the cost of operating all **AC switches** incurred by **Transpower** in the preceding **financial year** by the total number of **AC switches** less the product of 0.1 multiplied by the total number of **AC switches** operated by **customers** as follows:

$$ORR = \frac{OC}{TS}$$

where

OC is the cost associated with operating all **AC switches** incurred by

Transpower in the immediately preceding **financial year**, as determined by **Transpower** and recorded in its Maintenance Management System accounts for that **financial year** (expressed in dollars)

TS is the total number of **AC switches**, based on the number of switching devices in a **substation** or switching station, (as determined by **Transpower** and recorded in a **Transpower** asset register as at the end of the immediately preceding **financial year**) less the product of 0.1 multiplied by the total number of **AC switches** operated by **customers**.

Compare: Electricity Governance Rules 2003 clause 4.16 schedule F5 part F

Clause 19: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

20 Calculation of the Operating Component of the Connection Charge for a Connection Asset

The operating component of the **connection** charge for a **connection asset** is calculated by multiplying **ORR** by the number of **AC switches** that form part of the **connection asset** for which the **connection** charge is being calculated less the product of 0.1 multiplied by the number of **AC switches** within the **connection asset** that are operated by **customers** as follows:

$$O_{\text{conn}} = \text{ORR} \times S_{\text{conn}}$$

where

S_{conn} is the number of switches that form part of the **connection asset** for which the **connection** charge is being calculated, (as determined by **Transpower** and recorded in a **Transpower** asset register) less the product of 0.1 multiplied by the number of **AC switches** within the **connection asset** that are operated by **customers**.

Compare: Electricity Governance Rules 2003 clause 4.17 schedule F5 part F

Clause 20: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

21 Injection Overhead 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. The injection overhead component of the **connection** charge is calculated only for **connection assets** that **connect a customer's assets** at a **point of injection** to the **interconnection assets** and therefore applies only to **injection customers**.

Compare: Electricity Governance Rules 2003 clause 4.18 schedule F5 part F

Clause 21: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

22 Injection Overhead Revenue

The portion of AC overhead cost to be recovered from **injection customers** is referred to as **OHC_{inj}**. **OHC_{inj}** is calculated by reference to the proportion that the sum of the maintenance components for all **connection assets** for all **points of injection** bears to total maintenance costs of **AC assets** as follows:

$$OHC_{inj} = OHC_{AC} \times \frac{MC_{inj}}{MC_{AC}}$$

where

OHC_{AC} is the overhead cost component of **Transpower's AC revenue** for the relevant **pricing year**, as determined by Transpower when setting the **AC revenue**

MC_{inj} is the sum of the maintenance cost of the **connection assets** for all **points of injection** in the preceding **financial year**, as determined by **Transpower** and recorded in **Transpower's** Maintenance Management System accounts for that **financial year**

MC_{AC} is the sum of the maintenance cost of the **AC assets** in the preceding **financial year**, as determined by **Transpower** and recorded in **Transpower's** Maintenance Management System accounts for that **financial year**.

Compare: Electricity Governance Rules 2003 clause 4.19 schedule F5 part F

23 Injection Overhead Rate

The injection overhead rate used to calculate the injection overhead component of the **connection** charge is referred to as **IOR**. **IOR** is calculated by dividing **OHC_{inj}** by the sum of the proportion of the **replacement cost** of each **connection asset connecting injection customer** assets at all **points of injection** to the **interconnection assets** as follows:

$$IOR = \frac{OHC_{inj}}{\sum_{conn\ inj} RC_{conn\ inj} \times CA_{conn\ inj}}$$

where

RC_{conn inj} is the **replacement cost** of a **connection asset connecting injection customer assets** at a point of injection to the **interconnection assets**

$CA_{\text{conn inj}}$ is the **customer allocation** of the relevant **connection asset** for the relevant **injection customer** at the relevant **connection location**

$\sum_{\text{conn inj}} RC_{\text{conn inj}} \times CA_{\text{conn inj}}$ is the sum of all amounts calculated as $RC_{\text{conn inj}} \times CA_{\text{conn inj}}$ for all **injection customers' connection assets** for all **points of injection**.

Compare: Electricity Governance Rules 2003 clause 4.20 schedule F5 part F

Clause 23: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

24 Injection Overhead Component

The injection overhead component of the **connection charge** is calculated for a **connection asset** for a **point of injection** by multiplying the **IOR** by the **replacement cost** of that **connection asset** for which the **connection charge** is being calculated as follows:

$$IO_{\text{conn}} = \text{IOR} \times RC_{\text{conn inj}}$$

Compare: Electricity Governance Rules 2003 clause 4.21 schedule F5 part F

Clause 24: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

25 Customer Allocation

- (1) Each **customer** at a **connection location** is allocated a proportion (expressed as a percentage) of each **connection asset** for that **connection location**. This percentage is referred to as the **customer allocation** for that **connection asset** at that **connection location**. The **customer allocation** is calculated in accordance with subclause (2). If a **customer** is both an **offtake customer** and an **injection customer** at a **connection location**, a **customer allocation** for each **connection asset** for that **connection location** will be calculated for that **customer** as both an **offtake customer** and as an **injection customer**.
- (2) The **customer allocation** is calculated as follows:
 - (a) for a **connection asset** which connects only 1 **connection location** to **interconnection assets**, except for a **connection asset** of the kind referred to in clause (6)(1)(b)(ii), the **customer allocation** is the proportion that the **customer's anytime maximum demand** or **anytime maximum injection** (as the case may be) at that **connection location** bears to the sum of all **customers' anytime maximum demands** and **anytime maximum injections** at that **connection location**:
 - (b) for a **connection asset** which connects more than 1 **connection location** to **interconnection assets**, except for a **connection asset** of the kind referred to in clause (6)(1)(b)(ii), the **customer allocation** is the proportion that the **customer's anytime maximum demand** or **anytime maximum injection** (as the case may be) at that **connection location** bears to the sum of all **customers' anytime maximum demands** and **anytime maximum injections** at all **connection locations** for that **connection asset**:
 - (c) for a **connection asset** of the kind referred in clause (6)(1)(b)(ii), the **customer allocation** is the proportion that the **customer's anytime maximum demand** or **anytime maximum**

injection (as the case may be) at the **connection location** bears to the total capacity of that **connection asset**, as specified in a **Transpower** asset register.

- (3) The following table illustrates the calculation of an **offtake customer's annual connection charge** at a particular **connection location**. It lists all **connection assets** for that **connection location** and the proportion of the **connection charge** for each of those **connection assets** (including the amount of each of the asset, maintenance, and operating components of the **connection charge**) included in the **annual connection charge** together with the **customer allocation** for the relevant **connection asset**). The column headed "Recovery" is provided for information only and indicates whether the asset, maintenance and operating components (respectively) are recovered under this **transmission pricing methodology** (TPM) or under a **new investment contract** (NIC).

Connection charge report

2007 - Connection Charge Components

Customer: Southern Electric

Substation: Johnston Load Type: OFT

Asset	Asset Id	Physical Location	Recovery			Asset Value		Component		Customer Allocation %	Charge \$
			A	M	O	\$	\$	\$	\$		
LINE	JTN-PVL A		TPM	TPM		4,513,794	393,151	187,603	0	4.27	24,798
LAND/BLDGS	JTN	JTN	TPM	TPM		1,343,443	117,014	14,106	0	100.00	131,120
TRAN	T1	JTN	NIC	TPM		694,012	0	7,287	0	100.00	7,287
SWIT	1	JTN	TPM	TPM-TPM		113,644	9,898	1,193	1,104	100.00	12,195
SWIT	2	JTN	TPM	TPM-TPM-TPM		113,664	9,898	1,193	1,104	100.00	12,195
SWIT	3	JTN	NIC	TPM-TPM		113,664	0	1,193	1,104	100.00	2,297
SWIT	92	PVL	TPM	TPM-TPM		344,087	29,970	3,613	2,208	100.00	35,794

Compare: Electricity Governance Rules 2003 clauses 4.22 to 4.24 schedule F5 part F

Clause 25(3): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

26 Exceptions to the Application of the Connection Charge

- (1) If a **connection asset** is provided by **Transpower** under a **new investment contract**, in which the capital costs of that **connection asset** are recovered, calculation of the **connection charge** for that **connection asset** for the **customer** who is a party to that **new investment contract** (irrespective of when that agreement was entered into) is as follows:
- for the purposes of calculating the **connection charge** for that **connection asset** under clause 8(1), the asset component A_{conn} is \$0. Recovery of the amount that would otherwise be recovered as the asset component for that **connection asset** is determined by, and recovered under, the **new investment contract**, in accordance with the provisions of the **new investment contract**;
 - the maintenance component and operating component of the **connection charge** are calculated as per clauses 15, 17, and 20; and
 - if the **connection asset** connects more than 1 **connection location** or it connects a **connection location** at which there is more than 1 **customer**, the **customer allocation** is

determined in accordance with the relevant **new investment contract**, rather than in accordance with clause 25(2) of this **transmission pricing methodology**.

- (2) If **Transpower** has entered into a prudent discount agreement in which it is agreed that notional **connection assets** that form part of the **alternative project** specified in the prudent discount agreement substitute for **connection assets** at a **connection location**, then for the purposes of clause 8(1) the **customer's customer allocation** for the **connection assets** so substituted is deemed to be 0.
- (3) If a **customer** is **connected** at a **connection location** subject to an **input connection contract**, the following apply:
 - (a) those assets that the **customer** uses to **connect** at that **connection location** will not be included in the calculation of the total **connection charge** for that **connection location**;
 - (b) the **customer** will be charged in accordance with the terms of the applicable **input connection contract**.

Compare: Electricity Governance Rules 2003 clauses 4.25 to 4.27 schedule F5 part F

Clause 26: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Interconnection Charge

27 Interconnection Charge

The purpose of the interconnection charge is to recover the remainder of **Transpower's AC revenue** that is not recovered via **connection charges**. **Monthly interconnection charges** are paid by **offtake customers** in respect of each **connection location** at which they have **assets connected** to the **grid**. An **annual interconnection charge** is calculated for each **customer** at a **connection location** in accordance with clauses 28 to 30. A **customer's monthly interconnection charge** at that **connection location** is $\frac{1}{12}$ of the **annual interconnection charge**, subject to clause 34 of this **transmission pricing methodology**.

Compare: Electricity Governance Rules 2003 clause 5.1 schedule F5 part F

Clause 27: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

28 Interconnection Revenue

The portion of **AC revenue** to be recovered by interconnection charges is calculated as the difference between **Transpower's AC revenue** and the amounts recovered by the **connection charges** for that **pricing year** as follows:

$$R_{IC} = \text{AC revenue} - \sum \text{connection charges}$$

where

AC revenue is **Transpower's AC revenue** for the relevant **pricing year**

$\sum \text{connection charges}$ is the sum of all **connection charges** calculated for the relevant

pricing year.

Compare: Electricity Governance Rules 2003 clause 5.2 schedule F5 part F

Clause 28: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

29 Interconnection Rate

The interconnection rate used to determine the **annual interconnection charge** is referred to as **IR** and is the same for all **offtake customers** at all **connection locations** in all **regions**. The **IR** is calculated by dividing the interconnection revenue by the sum of the average of the **RCPDs** for each **customer** at a **connection location** for all **customers** at all **connection locations** for all **regions** as follows:

$$IR = \frac{R_{IC}}{\sum_{regions} \sum_{cust} \sum_{loc} \frac{1}{N_{reg}} \sum_{i=1}^{N_{reg}} RCPD_i}$$

where

R_{IC} is the interconnection revenue calculated in accordance with clause 28

$\sum_{regions} \sum_{cust} \sum_{loc} \frac{1}{N_{reg}} \sum_{i=1}^{N_{reg}} RCPD_i$ is the sum of the average **RCPDs** for each **customer** at a **connection location** for all **customers** at all **connection locations** for all **regions**.

Compare: Electricity Governance Rules 2003 clause 5.3 schedule F5 part F

30 Calculating the Interconnection Charge

An **annual interconnection charge** is calculated for each **offtake customer** at a **connection location** by multiplying the interconnection rate by the sum of the **customer's RCPD** at a **connection location** as follows:

$$\text{interconnection charge} = IR \times \frac{1}{N_{reg}} \sum_{i=1}^{N_{reg}} RCPD_i$$

where

IR is **IR**

$\frac{1}{N_{reg}} \sum_{i=1}^{N_{reg}} RCPD_i$ the average **RCPD** for the **offtake customer** in respect of whom the interconnection charge is being calculated at the relevant **connection locations**.

Compare: Electricity Governance Rules 2003 clause 5.4 schedule F5 part F

HVDC charge

31 HVDC Charge

The purpose of the HVDC charge is to recover **Transpower's HVDC revenue**. HVDC charges are paid by all **HVDC customers**. An **annual HVDC charge** is calculated for each **HVDC customer** at each **South Island generation connection location**. The **monthly HVDC charge** is $\frac{1}{12}$ of the **annual HVDC charge** subject to clause 34 of this **transmission pricing methodology**.

Compare: Electricity Governance Rules 2003 clause 6.1 schedule F5 part F

32 HVDC Rate

The HVDC rate used to calculate HVDC charges is referred to as **DCR** and expressed as \$/kW. **DCR** is calculated for each **pricing year** by dividing the **HVDC revenue** by the sum of the **HAMI** for the relevant **pricing year** for all **HVDC customers** at **all points of injection** where **South Island generation** connects (directly or indirectly) to the **grid assets** as follows:

$$DCR = \frac{R_{HVDC}}{\sum_{HVDC} HAMI_{HVDC}}$$

where

R_{HVDC} is **HVDC revenue** (expressed in dollars)

$\sum_{HVDC} HAMI_{HVDC}$ is the sum of **HAMI** (expressed in kW) of all **HVDC customers** at **all points of injection** where **South Island generation** connects (directly or indirectly) to the **grid assets**.

Compare: Electricity Governance Rules 2003 clause 6.2 schedule F5 part F

33 Calculating the HVDC Charge

The **annual HVDC charge** is calculated for each **HVDC customer** at each **South Island generation connection location** by multiplying **DCR** by the **HAMI** for the **HVDC customer** in respect of whom the **annual HVDC charge** is being calculated at each **South Island generation connection location** as follows:

$$HVDC \text{ charge} = DCR \times HAMI$$

where

DCR is **DCR**

HAMI is the **HAMI** for the **HVDC customer** in respect of whom the **annual HVDC charge** is being calculated at that **South Island generation**

connection location.

Compare: Electricity Governance Rules 2003 clause 6.3 schedule F5 part F

34 Adjustments to AMD, AMI, HAMI and RCPD and calculation of customer charges

(1) Before the start of a **pricing year**, and otherwise during a **pricing year** as provided in this clause, **Transpower** will calculate—

- (a) **AMD AMI, HAMI and RCPD** quantities (for each **regional peak demand period**); and
- (b) **annual charges**; and
- (c) **monthly charges**—

in each case for every **customer** at every **connection location** for that **pricing year**. When a **monthly charge** is recalculated for part of a **pricing year**, all inputs used in the calculation will be the same as those used to calculate that **monthly charge** before the start of the **pricing year** except for the adjustments specifically provided in this clause.

(2) If, when calculating **AMD, AMI, HAMI and RCPD** quantities before the start of a **pricing year**, **Transpower**, in its sole discretion, considers that exceptional operating circumstances during the relevant **capacity measurement period(s)** have resulted in—

- (a) abnormal **regional demand** resulting in an exceptional **regional peak demand period** for that **pricing year**; and/or
- (b) distortions to a **customer's AMD, AMI, HAMI and/or any RCPD** quantity at a **connection location** for that **pricing year**—

Transpower may, but is under no obligation to—

- (c) determine that the exceptional **regional peak demand period** is to be ignored when assessing the **regional peak demand periods** for that **pricing year**; and/or
- (d) adjust the **customer's AMD, AMI, HAMI and/or any RCPD** for the quantity at the relevant **connection location** to minimise the impact of such distortion, as assessed by **Transpower** acting reasonably but otherwise in its sole discretion, as applicable. Such adjusted **AMD, AMI, HAMI and RCPD** qualities, as the case may be, shall be used to calculate **monthly charges** for that **customer** for that **connection location** for that **pricing year**.

(2A) Subclause (2C) applies if—(a) a **customer** has given notice to **Transpower**, no later than 20 **business days** before the start of a **capacity measurement period** for a **pricing year**, that the **customer** proposes to change the amount or timing (or both) of the **customer's offtake** in the **capacity measurement period** compared with the **customer's previous offtake**; and

(b) the **customer** requests that **Transpower** applies the adjustment provided for under subclause (2C) in respect of the **customers change in offtake**; and

(c) **Transpower** is satisfied that—

(i) the change in **offtake** will alter the incidence of the majority of **regional peak demand periods** in the **region** in which the change in **offtake** will occur; and

(ii) the change in **offtake** is unlikely to occur in the absence of the adjustment provided for in subclause (2C); and

(iii) the change in **offtake** is unlikely to give rise to a need for investment in the **grid**; and

(d) **Transpower** has notified the **customer**, before the commencement of the **capacity measurement period**, that it intends to apply the adjustment provided for in subclause (2C) in respect of the **customer's change in offtake**.

(2B) **Transpower** must **publish** on its website the notice referred to in subclause (2A)(d).

(2C) When this clause applies in respect of a **customer's change in offtake**, **Transpower** must disregard the change for the purposes of identifying **regional peak demand periods in the region** in which the change occurs.

(3) If **Transpower**—

(a) is notified that **South Island generation** at a **connection location** has been permanently de-rated (including decommissioning) to a specified aggregate rate capacity (“maximum de-rated capacity”); and

(b) is satisfied that such **South Island generation** has been so permanently de-rated,—
then, for the purposes of calculating a **customer's HAMI** at the relevant **connection location** for any **pricing year** that commences not less than 6 months after the date on which **Transpower** is satisfied under paragraph (b), any **injection** at that **connection location** in any **half-hour** period up to the date on which **Transpower** is satisfied under paragraph (b) which:

(c) is used to determine the **customer's HAMI**; and

(d) exceeds the maximum de-rated capacity,—
will be deemed to be equal to the maximum de-rated capacity.

(4) If not less than 6 months before the start of a **pricing year**, **Transpower**—

(a) is notified that the **offtake** and/or **injection** capacity of a **customer's assets** at a **connection location** has been permanently de-rated (including decommissioning); and

(b) is satisfied that the **offtake** and/or **injection** capacity of such **assets** has been so permanently de-rated—

then, for the purpose of calculating the **customer's AMD, AMI** and/or **RCPD** quantities at that **connection location** for any **pricing year** that commences not less than 6 months after the date on which **Transpower** is satisfied under paragraph (b),—

(c) **Transpower** will estimate (acting reasonably but otherwise in its sole discretion) the **customer's likely future offtake** or **injection** (as the case may be) at that **connection location**, having regard to the change in the **customer's offtake** and/or **injection**; and

(d) **injection** or **offtake** quantities for any **half-hour** period up to the date on which **Transpower** is satisfied under paragraph (b) which—

(i) are used to determine the **customer's AMD, AMI** or **RCPD** quantities; and

(ii) exceed **Transpower's** estimate under paragraph (c),—
will be deemed to be no more than the amounts estimated by **Transpower** under paragraph (c).

(5) If—

(a) **Transpower** decommissions a **connection location**; or

(b) a **customer** causes all of its **assets connected** to the grid at a **connection location** to be, and **Transpower** is satisfied that the **customer's assets** have been, permanently disconnected from the **grid** at that **connection location**,—

then—

-
- (c) the **customer's monthly charges** for the month in which the **connection location** is decommissioned, will be pro-rated for the number of days that the **connection location** was decommissioned or **assets** were disconnected and the **monthly charges** will be reduced accordingly; and
 - (d) from the month following the month in which such decommissioning or disconnection occurred, the **customer's AMD, AMI, HAMI** and all **RCPD** quantities at that **connection location** and the **customer's monthly charges** at that **connection location** will be deemed to be 0.
- (6) If a **customer** connects **assets** to the **grid** at a **connection location** where that **customer** does not already have **assets connected** to the **grid** (including a **new connection location**), the following applies:
- (a) **Transpower** will agree with the **customer** whether the **customer** is to be an **offtake customer** or an **injection customer** at the relevant **connection location** and the **customer** will, until such time as the **assets** have been **connected** for a full **capacity measurement period**, be deemed to be an **offtake customer** and/or an **injection customer** accordingly;
 - (b) if the **asset** is a **generating unit** or **generating station** located in the South Island, the **generating unit** or **generation station** will be deemed to be **South Island generation**;
 - (c) **Transpower** will assign the **new connection location** to a **region** (unless it is an existing **connection location**);
 - (d) from the time of **connection** of the **assets** until such time as the **assets** have been **connected** to the **grid** for the whole of the **capacity measurement period** for a **pricing year**, or, in the case of **assets** which are deemed to be **South Island generation** under paragraph (b), have been **connected** to the **grid** for 5 consecutive **capacity measurement periods**, the **customer's AMD, AMI, HAMI** and **RCPD** quantities at the **connection location** will be determined using **Transpower's** estimates of the **customer's** likely **offtake** and/or **injection** at the **connection location** for that period;
 - (e) the **customer** will pay **monthly charges** at the **connection location** from the date the **customer's assets** are **connected** to the **grid**. If the **customer's assets** are **connected** part way through a month, the **monthly charges** for that month will be reduced by an amount, being a pro-rata proportion of the **monthly charges** for the number of days in the month that the **customer's assets** were not **connected**.
- (7) If—
- (a) a **customer's connection** of new **assets** at a **connection location** to which subclause (5) applies, (the “first **connection location**”) is a direct consequence of that **customer's** de-rating of **assets** at another **connection location**, (the “second **connection location**”) without the **customer** terminating the second **connection location** as a **point of connection** under any relevant **transmission agreement**; and
 - (b) the **connection assets** for the second **connection location** are shared with any other **customer**,—
- then—
- (c) **Transpower** will estimate (acting reasonably but otherwise in its sole discretion) the **customer's** likely **offtake** or **injection** at the second **connection location** from the date on

which the new **assets** are **connected** at the first **connection** location (“load transfer date”) until those assets have been **connected** to the **grid** for the whole of a **capacity measurement period** for a **pricing year**; and

- (d) the **customer’s monthly connection charges** at the second **connection** will be recalculated from the load transfer date. When recalculating the **customer’s monthly connection charges** from the load transfer date, any **injection** and/or **offtake** prior to the load transfer date used to calculate the **customer’s AMD** and/or **AMI** at the second **connection** location will be capped at **Transpower’s** estimates in accordance with subclause (6)(a); and
 - (e) if the load transfer date occurs part way through a month, the **customer’s monthly connection charges** at the second **connection** location for that month will be the sum of:
 - (i) a pro-rata proportion of the **customer’s monthly connection charges** at the second **connection** location immediately before the load transfer date, based on the number of days in the month prior to the load transfer date; and
 - (ii) a pro-rata proportion of the **customer’s monthly connection charges** at the second **connection location** recalculated in accordance with subclause (6)(e), based on the number of days in the month including and subsequent to the load transfer date.
- (8) If **Transpower** enhances or upgrades **connection assets** for a **connection location** under a **new investment contract** with a **customer** (a “NIC customer”), excluding NIC customers to whom subclause (5) applies,—
- (a) if the enhancement or upgrade is commissioned part way through a **pricing year**, **monthly connection charges** at that **connection location** for the NIC customer will be recalculated from the date the enhanced or upgraded **connection assets** are commissioned to take into account those enhanced or upgraded **connection assets**; and
 - (b) if the **connection asset** enhancement or upgrade is commissioned part way through a month, the NIC **customer’s monthly connection charge** for that month will be the recalculated **monthly connection charge** reduced by an amount, being a pro-rata proportion of the recalculated **monthly connection charge** for the number of days in the month before commissioning of the enhancement or upgrade.
- (9) If under this clause, **Transpower** estimates a **customer’s likely offtake** or **injection** over any period, **Transpower** may, but is not obliged to, review its estimate from time to time, but not more frequently than at 3 monthly intervals. If **Transpower** revises its estimate, the **customer’s**—
- (a) **AMD, AMI, HAMI and RCPD** quantities; and
 - (b) **monthly charges**—
- will be recalculated accordingly and such recalculated **monthly charges** will be payable upon **Transpower** giving such notice as required in the relevant **transmission agreement** with the **customer**.
- (10) If subclauses (6), (7) or (8) apply, or **Transpower** revises any estimate and **monthly grid charges** under subclause (9), there will be a wash-up and reconciliation at the end of the relevant **pricing year** of—
- (a) **monthly connection charges** paid by—

-
- (i) all **customers** at the **connection location**; and
 - (ii) all other **customers** at **connection locations** which share the same **connection assets**; and
 - (b) **monthly HVDC charges** paid by all **HVDC customers**,—
in each case, in that **pricing year** as follows:
 - (c) in the case of **monthly connection charges**, the wash-up and reconciliation is to be undertaken in respect of all charges calculated in accordance with clause 8(1) for each shared **connection asset**—
 - (i) using **AMD** or **AMI** for each **customer** as at the last day of the **pricing year** (including any **Transpower** estimate); and
 - (ii) so that the sum of the percentage proportions allocated to **customers** in accordance with clause 25(1) does not exceed 100% for any **connection asset** and so that **Transpower**, in turn, does not recover, in aggregate, more than 100% of the sum of the asset, maintenance, operating and overhead cost components calculated in accordance with clauses 8 to 26 for any **connection asset**:
 - (d) in the case of **monthly HVDC charges**, the wash-up and reconciliation is to be undertaken—
 - (i) using **HAMI** for each **HVDC customer** as at the last day of the **pricing year**; and
 - (ii) so that the sum of all **monthly HVDC charges** paid by the **HVDC customer** for that **pricing year** does not exceed the **HVDC revenue** for that **pricing year**:
 - (e) **Transpower** will issue a credit note for any overpayment by a **customer** consequent upon the wash-up.
- (11) If a prudent discount agreement commences part way through a **pricing year**, **Transpower** will recalculate the **customer's monthly charges** at the relevant **connection location(s)** consistently with the prudent discount agreement from the date the prudent discount agreement takes effect until it terminates or otherwise ceases to apply. If the prudent discount agreement commences part way through a month, the customer's **monthly charges** for that month will be the sum of—
- (a) a pro-rata proportion of the **monthly charges** calculated in accordance with this **transmission pricing methodology** being the proportionate number of days in the month before the commencement of the prudent discount agreement; and
 - (b) a pro-rata proportion of the **monthly charges** calculated in accordance with the prudent discount agreement being the proportionate number of days in the month on and from commencement of the prudent discount agreement.
- (12) **Transpower must adjust a customer's AMD, AMI, HAMI, or RCPD at a connection location to minimise the impact of reverse flow at the connection location if—**
- (a) **the customer has notified Transpower that there is reverse flow at the connection location; and**
 - (b) **Transpower agrees that there is reverse flow at the connection location.**

Compare: Electricity Governance Rules 2003 clause 7 schedule F5 part F

Clause 34(5), (6) and (7): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Transmission alternatives

35 Transmission Alternatives

- (1) Charges for **transmission alternative** services will apply when **transmission alternative** services are provided and/or funded by **Transpower**. **Transmission alternative** services are services which substitute for the services provided by **connection assets** or **interconnection assets** or both.
- (2) If a **transmission alternative** service substitutes for a service which would otherwise be provided by **connection assets**, a charge recovering **Transpower's** costs of funding that **transmission alternative** service is added to the **connection** charge(s) of the **customer(s)** for the relevant **connection location(s)**. The costs of the **transmission alternative** service are allocated between all **customers** at the relevant **connection locations(s)** in the same proportion that each **customer's** total **connection** charges for the relevant **connection location(s)** bears to the sum of all **customers' connection** charges for those **connection location(s)**.
- (3) If a **transmission alternative** service substitutes for services which would otherwise be provided by **interconnection assets** a charge recovering the cost of the **transmission alternative service** is allocated between **offtake customers** in the same proportion that each **offtake customer's** interconnection charges bears to the sum of all **offtake customers' interconnection** charges.
- (4) If a **transmission alternative** service substitutes for both **connection assets** and **interconnection assets**, the allocation of the costs of the **transmission alternative service** as between **connection assets** and **interconnection assets** is made according to the rules set out in clause 25(2) for shared **connection assets** at an **interconnection node**.
- (5) The costs of funding **transmission alternative** services will be charged to, and payable by, **customers** in the month following the month in which **Transpower** is invoiced for those costs.

Compare: Electricity Governance Rules 2003 clause 8 schedule F5 part F

Clause 35(2): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Prudent Discount Policy

36 Purpose of the Prudent Discount Policy

- (1) The purpose of the prudent discount policy is to help ensure that the **transmission pricing methodology** does not provide incentives for the uneconomic bypass of existing **grid assets**. The prudent discount policy aims to deter investment in **alternative projects** which would allow a **customer** to reduce its own transmission charges while increasing the total economic costs to the nation as a whole.
- (2) In order for a **customer** to obtain a prudent discount a **customer's alternative project** must be—
 - (a) technically, operationally and commercially viable and have a reasonable prospect of being able to be successfully implemented; and
 - (b) uneconomic to implement given **Transpower's** economic costs of providing existing **grid assets** and the economic costs that would be incurred by the customer if it proceeded with the **alternative project**,—

determined in accordance with this prudent discount policy.

Compare: Electricity Governance Rules 2003 clauses 9.1 and 9.2 schedule F5 part F

37 Information Required in a Prudent Discount Application

- (1) In order for an **alternative project** to be accepted by **Transpower** as a prudent discount application it must be developed to a level of detail equivalent to the detail that a prudent company Board would reasonably expect when considering an investment proposal.
- (2) If a **customer** wishes to apply for a prudent discount, that **customer** must (at its own expense) submit to **Transpower** a written proposal describing the **alternative project** and the likely impact of that **alternative project** on that **customer's** transmission charges.
- (3) The proposal must, to the extent relevant, contain all of the information described in Appendix C, together with any other information which is likely to be relevant to **Transpower's** consideration of the **alternative project**.
- (4) Without limiting subclause (3) **Transpower** may require the **customer** to provide any additional information which **Transpower** considers is reasonably necessary to enable it to conduct its assessment of the **alternative project** in accordance with clauses 38 and 39.

Compare: Electricity Governance Rules 2003 clauses 9.3 to 9.6 schedule F5 part F

38 Assessment of Technical, Operational and Commercial Viability of Alternative Project

- (1) **Transpower** will, within a reasonable time of receiving the proposal, assess the **alternative project** to determine whether or not—
 - (a) it is technically feasible; and
 - (b) it is operationally feasible and compliant with the **asset owner performance obligations** and **technical codes**, and any other relevant requirements as set out in Part 8 of this Code; and
 - (c) the **alternative project** could reasonably be expected to provide the **customer** with transmission charges that would result in a lower overall commercial cost having regard to the capital, operating, maintenance and all other costs likely to be incurred by the **customer** as a result of undertaking the **alternative project** to the **customer** than the current **Transpower** charges, for the same or a similar level of service.
- (2) In undertaking its assessment of the **alternative project**, **Transpower** may adjust any of the information provided by the **customer** to reflect **Transpower's** reasonable assessment of current market prices, good engineering practice and any consequential impacts of the **alternative project** on the **grid assets** and the **customer's** assets.

Compare: Electricity Governance Rules 2003 clauses 9.7 and 9.8 schedule F5 part F

39 Assessment that the Alternative Project is Uneconomic

- (1) If **Transpower** considers that the **alternative project** does not satisfy one or more of the criteria specified in clause 38(1), no prudent discount will be provided.
- (2) If **Transpower** considers that the **alternative project** satisfies all of the criteria specified in clause 38(1), **Transpower** will, within a reasonable time thereafter, assess the **alternative project** to determine whether or not it is uneconomic in accordance with subclauses (3) to (7).

-
- (3) **Transpower** will calculate the present value of the estimated total costs of the **alternative project** including capital costs and operating and maintenance costs. **Transpower** may use the cost estimates provided by the **customer** or may reasonably adjust those costs to reflect current market prices, good engineering practice and consequential impacts of the **alternative project** on **grid assets** and the **customer's assets**.
 - (4) The discount rate used to undertake the calculations required by subclauses (3) to (7) must be a discount rate determined by the **Authority**, from time to time, or if the **Authority** has not determined a discount rate, a discount rate of, or equivalent to, a pre-tax real rate of 7%. The calculations required by subclauses (3) to (7) will be carried out using a period of 15 years or the remaining life of the **grid assets** which the **alternative project** would bypass, whichever is the lesser.
 - (5) **Transpower** will then calculate the present values of—
 - (a) **Transpower's** costs of continuing to provide transmission services to the **customer** if the **alternative project** does not proceed, including operating and maintenance costs and planned future capital expenditure needed to maintain required service levels; and
 - (b) **Transpower's** costs of continuing to provide transmission services to the **customer** if the **alternative project** does proceed, including operating and maintenance costs and planned future capital expenditure needed to maintain required service levels.
 - (6) If the amount calculated under subclause (5)(a) minus the amount calculated under subclause (5)(b) is greater than the amount calculated under subclause (3), the **alternative project** will be determined to be economic and no discount will be provided.
 - (7) If the amount calculated under subclause (5)(a) minus the amount calculated under subclause (5)(b) is less than the amount calculated under subclause (3), the **alternative project** will be determined to be uneconomic.

Compare: Electricity Governance Rules 2003 clauses 9.9 to 9.15 schedule F5 part F

40 Independent Review

- (1) The **customer** may, within 60 days of being notified of **Transpower's** decision to offer a prudent discount agreement or that no discount will be provided, request a review by an **independent expert** of any or all of the assessments undertaken by **Transpower** for the purposes of that decision.
- (2) Within a reasonable time of being appointed, the **independent expert** is to report his or her findings to **Transpower** and the **customer**. The findings of the **independent expert** will be binding on **Transpower** and the **customer**. If the **independent expert** finds that the **customer's alternative project** is uneconomic and satisfies all the requirements of clause 38(1), the provisions of clause 41(1) will apply.
- (3) The costs of the **independent expert** are to be met by the party requesting the review if the information or assessments reviewed are confirmed as reasonable; otherwise the costs will be met by the other party.

Compare: Electricity Governance Rules 2003 clauses 9.16 to 9.18 schedule F5 part F

41 Prudent Discount Agreement

- (1) If the **customer's alternative project** is considered by **Transpower** to be uneconomic and to satisfy all the requirements of clause 38(1), **Transpower** will offer a prudent discount agreement to all **customers** that are directly affected by the proposal. The prudent discount agreement will provide for—
- (a) the **customer** to pay to **Transpower** an annuity (the amount of which is to be specified in the prudent discount agreement) determined by reference to the **customer's** cost of funding, maintaining and operating the **alternative project** over the duration of the prudent discount agreement, applying a commercial discount rate; and
 - (b) **Transpower** to calculate the **customer's** transmission charges in accordance with this **transmission pricing methodology** as if the **alternative project** had been implemented.
- (2) The commencement date of a prudent discount agreement will take full account of the time that would reasonably be required for the **customer** to implement the **alternative project**.
- (3) The duration of a prudent discount agreement will be the lesser of the remaining economic life of the **grid assets** that are affected by the agreement, or 15 years.

Compare: Electricity Governance Rules 2003 clauses 9.19 to 9.21 schedule F5 part F

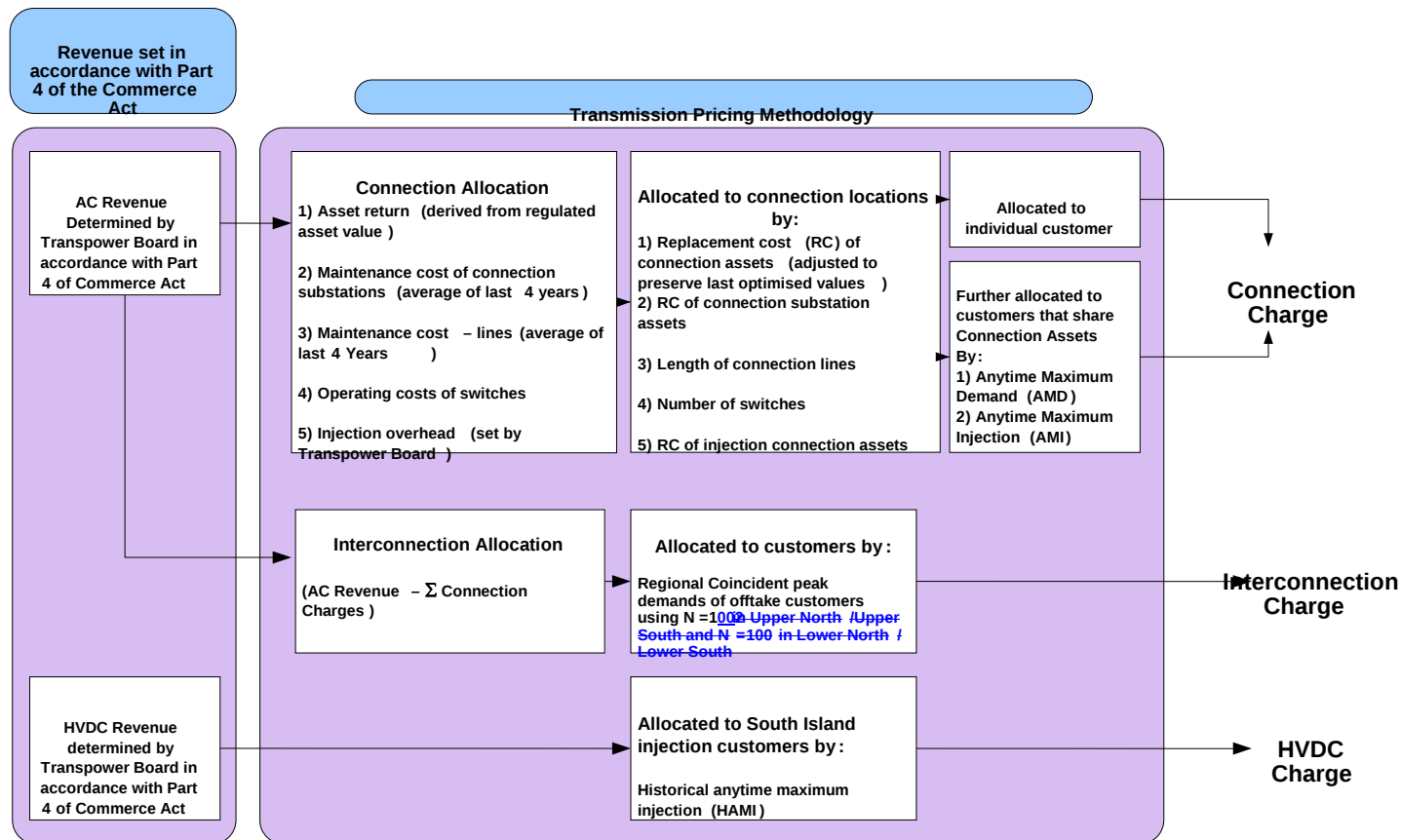
42 Prudent Discount Details to be Published

- (1) As soon as reasonably practicable after concluding a prudent discount agreement with a **customer**, **Transpower** must publish on its website the decision made, the analysis supporting that decision and the following information:
- (a) the cost estimate used by **Transpower** in assessing the **alternative project** and the calculations undertaken by **Transpower** using those cost estimates;
 - (b) any report prepared by an **independent expert**;
 - (c) the annual amount payable by the **customer** under clause 41(1)(a);
 - (d) details of how the **customer's** transmission charges will be calculated under clause 41(1)(b).

Compare: Electricity Governance Rules 2003 clause 9.22 schedule F5 part F

Electricity Industry Participation Code 2010
Schedule 12.4, Appendix A

Appendix A– Allocation of Transpower’s AC Revenue and HVDC Revenue to its Charges



Compare: Electricity Governance Rules 2003 appendix A schedule F5 part F

Appendix B Regions

North Island

The Upper North Island (UNI) is [all of the connection locations in-described in the Annual Planning Report \(APR\)](#) as “the geographical area north of Huntly, including Glenbrook, Takanini, Auckland and the Northern Isthmus”.

The [connection locations](#) in the UNI region are:

Code	Name
ALB	Albany
BOB	Bombay
BRB	Bream Bay
DAR	Dargaville
GLN	Glenbrook
HEN	Henderson
HEP	Hepburn Rd
HLV	Huntly
KEN	Kensington
KOE	Kaikohe
KTA	Kaitaia
MDN	Marsden
MER	Meremere
MNG	Mangere
MPE	Maungatapere
MTO	Maungaturoto
OTA	Otahuhu
PAK	Pakuranga
PEN	Penrose
ROS	Mt Roskill
SVL	Silverdale
SWN	Southdown
TAK	Takanini
TWH	Te Kowhai
WEL	Wellsford
WES	Western Rd
WIR	Wiri

The remainder of the **connection locations** in the North Island are in the [Lower North Island \(LNI\)](#) region.

South Island

The Upper South Island (USI) is all of the **connection** locations in the geographical area that includes defined in terms of all **GXP**s supplied from the major concentration of generation in the Waitaki Valley and south of the Waitaki Valley. These GXP's are supplied by the 220kV system from Tekapo B, Twizel and Livingstone (refer Fig 5-19 in the APR).

The ~~connection locations~~ in the USI region are:

Code	Name
ABY	Albury
ADD	Addington
APS	Arthurs Pass
ARG	Argyle
ASB	Ashburton
ASY	Ashley
BLN	Blenheim
BRV	Bromley
CLH	Castle Hill
COB	Cobb
COL	Coleridge
CUL	Culverden
DOB	Dobson
GYM	Greymouth
HKK	Hokitika
HOR	Hororata
ISL	Islington
KAI	Kaiapoi
KIK	Kikiwa
KKA	Kaikoura
KUM	Kumara
MCH	Murchison
MOT	Motueka
MPI	Motupipi
ORO	Orowaiti
OTI	Otira
PAP	Papanui
RFT	Reefton
SBK	Southbrook
SPN	Springston
STK	Stoke
UTK	Upper Takaka

Electricity Industry Participation Code 2010
Schedule 12.4, Appendix B

TIM	Timaru
TKA	Tekapo A
TMK	Temuka
WPR	Waipara
WPT	Westport

The remainder of the **connection locations** in the South Island are in the [Lower South Island \(LSI\)](#) region.

Compare: Electricity Governance Rules 2003 appendix B schedule F5 part F

Appendix C

Information Required to Support a Prudent Discount Application

General information

1. Location of the **alternative project**.
2. A brief description of the **alternative project**.
3. A sketch or schematic of the **alternative project**.

Part A: Information required to enable a technical evaluation of the proposal

- (1) A report on the technical viability of the **alternative project**, provided by either the **customer**, or an external consultant on behalf of the **customer**. The report must include details of voltage quality, especially if there are switched capacitors and/or switched loads, such as motor starting, and information on the size of load, the size of any capacitors, the frequency of switching and the size of voltage steps.
- (2) A circuit diagram.
- (3) For a **customer** who operates a distribution network, a diagram of the **customer's** distribution network that is sufficiently detailed to run load-flow models. The network diagram should contain load distribution data, circuit parameters and the parameters of any embedded generation.
- (4) A description of how the requirement for any additional physical space will be met. (When attaching to existing equipment, or to an existing facility, there may be a need for physical space for new equipment, e.g. a new circuit breaker bay or a **connection** point to a generator bus.)
- (5) The following information, except if it is not applicable to the **alternative project**:
 - Voltage (kV)
 - Demand (peak MW/low MW)
 - Conductor rating and type
 - Circuit length (km) and type (single or double)
 - Voltage support type and rating (VARs)
 - Estimated losses (MW/km)
 - Transformers: size (VA) and impedance (Ω)

Part B: Cost of the alternative project

The following information is required to enable independent validation of the **customer's** cost estimates. This information must be provided, except if it does not apply to the **alternative project**.

Capital cost (line)

- (1) Conductor type, capital cost per metre, distance in metres and total estimated cost.
- (2) Type of structures (poles or lattice towers), number of structures, capital cost per structure and total estimated cost.
- (3) Type and number of insulators, capital cost per insulator and total estimated cost.
- (4) The capital cost of line fittings.

- (5) Any other capital costs of lines.

Capital cost (substation)

- (1) The type and number of transformers, the capital cost per unit and the total estimated cost.
- (2) The type and number of circuit breakers, the capital cost per unit and the total estimated cost.
- (3) The type and number of disconnectors, the capital cost per unit and the total estimated cost.
- (4) The type of protection and metering, the capital cost per unit and the total estimated cost.
- (5) The type and capital cost of buswork.
- (6) The type and capital cost of other infrastructure.
- (7) Any other miscellaneous substation costs.

Labour cost

- (1) Estimated labour costs.
- (2) Estimated design and project management costs.

Cost of system losses

The estimated cost of the electrical line losses that would result if the alternative were implemented, specifically:

- Estimated additional losses in MW/km.
- Estimated additional losses per annum in MWh.
- The estimated average price of energy in \$/MWh.
- Total estimated value of additional electrical losses per annum in dollars.

The cost of easements and consents

- (1) A topographical map of the line route in sufficient detail to verify estimates of the costs of easements and consents, or to verify that easements and consents are not required.
- (2) An estimate of consent costs.
- (3) An estimate of easements costs.
- (4) Estimate of property right costs.

Part C: Commercial evaluation

An analysis by the **customer** that provides a prima facie demonstration that the proposed **alternative project** would provide the **customer** with **Transpower** charges that would result in a lower overall commercial cost to the **customer** than the current **Transpower** charges, for the same or a similar level of service.

Part D: Legal matters

The implementation of some **alternative project** proposals will require the **customer** to enter into contractual agreements with third parties and to satisfy statutory requirements. In this case, the **customer** must provide reasonable evidence that the **alternative project** would be able to be successfully implemented, including but not limited to—

- (1) a report from appropriately qualified planning, legal and property consultants that demonstrates that all consents required to implement the **alternative project** are either held, or are reasonably likely to be obtained; and
- (2) evidence of access, easement and other property rights required to implement the alternative project.

Compare: Electricity Governance Rules 2003 appendix C schedule F5 part F

Part A(4): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 20

Appendix C The current HVDC, interconnection and connection charges

- C.1 The current TPM comprises:
- (a) the HVDC charge (which uses the HAMI allocator).
 - (b) the interconnection charge (which uses the RCPD allocator)
 - (c) the connection charge.

The HVDC charge

- C.2 The HVDC charge recovers the costs of the HVDC link between the NI and SI. In simple terms, it is a charge on all South Island generation, in proportion to maximum net injection into the transmission grid.
- C.3 The HVDC charge is paid by customers at each SI generation connection location – i.e. where any generating unit or station located in the SI is either connected directly to the grid, or connected to a local network that is connected (directly or indirectly) to the grid.⁴⁵
- C.4 For a given year, the HVDC charge is calculated for each HVDC customer at each SI generation connection location by multiplying Transpower's required HVDC revenue by the ratio of the customer's HAMI at the location to the sum of the HAMI of all HVDC customers at all SI generation connection locations.⁴⁶
- C.5 HAMI for a transmission customer at a SI generation connection location in a given pricing year⁴⁷ is defined as the highest of:⁴⁸
- (a) the average of the 12 highest injections at that location during the capacity measurement period⁴⁹ for the pricing year, or
 - (b) the average of the 12 highest injections at that connection location during any of the four immediately preceding pricing years. (Note, there is overlap between the capacity measurement period for the pricing year, and the previous pricing year.)
- C.6 If, in Transpower's view, there are exceptional operating circumstances that have led to distortions in HAMI, the Code allows Transpower to adjust HAMI quantities to minimise the distortion.⁵⁰

⁴⁵ Clause 31 of the TPM.

⁴⁶ Clauses 32-33 of the TPM.

⁴⁷ Under clause 3 of the TPM, a pricing year runs from 1 April to 31 March.

⁴⁸ Clause 3 of the TPM.

⁴⁹ Under clause 3 of the TPM, the capacity measurement period means for any pricing year, the 12 month period starting 1 September and ending 31 August inclusive, immediately before the commencement of the pricing year.

⁵⁰ Clause 34(2) of the TPM.

- C.7 If SI generation is permanently derated or decommissioned, then Transpower can adjust HAMI quantities downwards to reflect the new capacity.⁵¹
- C.8 If new SI generation connects to the grid, Transpower will initially base the new generator's charges on an estimate of its maximum injection.⁵²
- C.9 Under the prudent discount policy, Transpower can enter into a prudent discount agreement in order to avoid incentivising inefficient embedding of SI generation.⁵³ Also, some 'notional embedding contracts' – the precursor to prudent discount agreements – were signed before 2008 and are still operative.
- C.10 In the 2015/16 pricing year, the HVDC rate is forecast to be \$46.49/kW and the HVDC charge is forecast to collect \$149.93 million.⁵⁴ The capacity measurement period for 2015/16 is 2013/14.

The interconnection charge

- C.11 The interconnection charge recovers all Transpower's TPM costs that are not recovered through the HVDC charge or the connection charge.⁵⁵ In simple terms, it is a charge on all load that takes power from the transmission grid, in proportion to net offtake at regional peak times.
- C.12 The interconnection charge is considered to be a 'postage stamp' charge, because the interconnection rate is the same for all offtake customers and all connection locations in all regions.
- C.13 The interconnection charge is paid to Transpower by offtake customers – i.e. lines companies and major consumers that have assets connected directly to Transpower's grid.
- C.14 For a given pricing year, the interconnection charge is calculated for each offtake customer at each connection location by multiplying the interconnection rate by the average of the customer's regional coincident peak demand (RCPD) at the connection location across regional peaks in the capacity measurement period⁵⁶ for that pricing year.⁵⁷
- C.15 The interconnection rate is calculated by dividing Transpower's required interconnection revenue by the sum over all customers and connection locations

⁵¹ Clause 34(3) of the TPM.

⁵² Clause 34(6) of the TPM.

⁵³ Clauses 36-42 of the TPM. See also <https://www.transpower.co.nz/about-us/industry-information/revenue-and-pricing>.

⁵⁴ <https://www.transpower.co.nz/about-us/industry-information/revenue-and-pricing#pricing>

⁵⁵ Clause 27 of the TPM.

⁵⁶ Under clause 3 of the TPM, the capacity measurement period means for any pricing year, the 12 month period starting 1 September and ending 31 August inclusive, immediately before the commencement of the pricing year.

⁵⁷ Clause 30 of the TPM.

of the average of RCPD across regional peaks in the capacity measurement period⁵⁸ for that pricing year.⁵⁹

- C.16 A customer's RCPD at a connection location during a regional peak is defined as their offtake at that connection location in the relevant trading period.⁶⁰
- C.17 The regional peaks in a pricing year are:⁶¹
- (a) the 12 trading periods where total regional demand is highest, for the UNI and USI regions
 - (b) the 100 trading periods where total regional demand is highest, for the LNI and LSI regions.
- C.18 In other words, the RCPD allocator uses N=12 for the UNI and USI, but N=100 for the LNI and LSI.
- C.19 Regions are defined as follows:⁶²
- (a) the UNI is the part of the NI that is north of Huntly, including Huntly and Te Kowhai but excluding Hamilton, Waihou, Waikino and Kopu
 - (b) the USI is the part of the SI that is north of the Waitaki Valley, including Ashburton, Tekapo A, Albury, Timaru and Temuka but excluding Tekapo B and the other Waitaki Valley nodes.
- C.20 If, in Transpower's view, there are exceptional operating circumstances that have led to distortions in RCPD, the Code allows Transpower to adjust RCPD quantities to minimise the distortion.⁶³
- C.21 If assets are permanently derated or decommissioned, then Transpower can adjust RCPD quantities to reflect the new capacity.⁶⁴
- C.22 When new assets are connected to the grid, Transpower initially bases charges on estimates.⁶⁵
- C.23 Under the prudent discount policy, Transpower can provide a prudent discount in order to avoid incentivising inefficient bypass of existing grid assets.⁶⁶ Also, some

⁵⁸ Under clause 3 of the TPM, the capacity measurement period means for any pricing year, the 12 month period starting 1 September and ending 31 August inclusive, immediately before the commencement of the pricing year.

⁵⁹ Clause 29 of the TPM.

⁶⁰ Clause 3 of the TPM.

⁶¹ Clause 3 of the TPM.

⁶² See Appendix B of Schedule 12.4 of the Code.

⁶³ Clause 34(2) of the TPM.

⁶⁴ Clause 34(4) of the TPM.

⁶⁵ Clause 34(6) of the TPM.

⁶⁶ Clauses 36-42 of the TPM. See also <https://www.transpower.co.nz/about-us/industry-information/revenue-and-pricing>.

'notional embedding contracts' – the precursor to prudent discount agreements – were signed before 2008 and are still operative.

- C.24 In consequence, when calculating RCPD and identifying regional peaks, Transpower:
- (a) in some cases, treats several load nodes at the same substation as if they were a single node – allowing injection at one node to be offset against offtake at another node
 - (b) in some cases, treats load nodes and nearby generation nodes as if they were a single node – allowing injection at the generation node to be offset against offtake at the load node.
- C.25 In the 2015/16 pricing year, the interconnection rate is forecast to be \$110.35/kW and the interconnection charge is forecast to collect \$632.19 million.⁶⁷ The capacity measurement period for 2015/16 is 2013/14.

The connection charge

- C.26 The connection charge recovers the costs of providing connection services, other than those costs that are recovered outside the TPM (e.g. costs recovered through investment contracts between Transpower and connected parties⁶⁸).
- C.27 In broad terms, a connection asset is:⁶⁹
- (a) at a connection node, any grid asset other than voltage support equipment that is for grid voltage support purposes that has not been installed at a customer's request
 - (b) at an interconnection node:
 - (i) any grid asset that is specifically required to connect a customer
 - (ii) any grid asset that is used both to connect a customer and for grid operation generally
 - (iii) a proportion of the land and buildings at the connection location
 - (c) any grid asset that is a connection link.
- C.28 In each pricing year, a connection charge is calculated for each connection asset. The charge is the sum of the following components:⁷⁰
- (a) an asset component

⁶⁷ <https://www.transpower.co.nz/about-us/industry-information/revenue-and-pricing#pricing>.

⁶⁸ Clause 26 of the TPM.

⁶⁹ Clause 6 of the TPM. See also Clause 5 of the TPM, which defines connection nodes, interconnection nodes, and connection links.

⁷⁰ Clause 8 of the TPM.

- (b) a maintenance component
 - (c) an operating component
 - (d) for injection customers, an overhead component.
- C.29 The largest in magnitude is the asset component, followed by the maintenance component. The operating and overhead components are considerably smaller.
- C.30 The asset component recovers a share of the capital cost of, and depreciation on, 'pool' connection assets – i.e. those that are not paid for through investment contracts.⁷¹ As previously noted by the Authority,⁷² the charge for each asset is proportional to the replacement value of that asset, rather than being linked to the age or condition of the asset.
- C.31 The maintenance component recovers a share of the maintenance costs of all connection assets.⁷³ As previously noted by the Authority,⁷⁴ the charge for each asset is proportional to the replacement cost (if a substation) or the length (if a line), rather than reflecting the cost of the actual maintenance performed on that specific asset.
- C.32 The operating component recovers a share of the operating costs of all connection assets.⁷⁵
- C.33 The overhead component recovers a portion of AC operating and maintenance costs from generators, because they do not otherwise contribute to meeting these types of costs.⁷⁶
- C.34 The connection charge for each connection asset is allocated between Transpower's customers using that connection asset. The allocation to a customer at a connection location is proportional to the customer's anytime maximum injection (AMI) or anytime maximum demand (AMD) at that location.⁷⁷
- C.35 The Code provides for various adjustments to the AMI and AMD quantities to be used when calculating the connection charge.⁷⁸
- C.36 In the 2015/16 pricing year, the connection charge is forecast to collect \$127.68 million.⁷⁹

⁷¹ Clauses 10-12 of the TPM.

⁷² <http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c12271>

⁷³ Clauses 13-17 of the TPM.

⁷⁴ <http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c12271>

⁷⁵ Clauses 18-20 of the TPM.

⁷⁶ Clauses 21-24 of the TPM.

⁷⁷ Clause 25 of the TPM.

⁷⁸ Clause 34(6) of the TPM.

Appendix D Transpower's consultations

- D.1 This Appendix briefly describes the two consultations carried out by Transpower's in the course of its operational review of the TPM. For more information (including consultation papers and submissions), see Transpower's website.⁸⁰ For more information on the current TPM, see Appendix C.
- D.2 Transpower's initial consultation paper under its operational review of the TPM, published in July 2014:
- (a) set out the purpose of the review and the process that Transpower would follow
 - (b) explained how Transpower's review would interact with the Authority's review
 - (c) identified the following problems:
 - (i) the HAMI allocator of HVDC charges has distortionary effects
 - (ii) the interconnection charge may provide an excessively strong signal for reductions in net load in the UNI, LNI and/or LSI regions
 - (iii) the large size of the Tiwai smelter relative to LSI regional demand can cause *'unstable pricing signals'*
 - (iv) there has been a *'significant uplift in the maintenance rate for poles'*, which is not cost-reflective
 - (v) charges *'are not allocated as expected'* when there are reverse flows
 - (d) identified the following possible solutions:
 - (i) greatly increasing the number of peaks used in the HAMI allocator, or moving to a per-MWh or 'incentive-free' allocator
 - (ii) increasing the value of N used for the RCPD allocator in the UNI, LNI and/or LSI regions
 - (iii) combining the UNI, LNI and LSI RCPD regions
 - (iv) changing the formula for the line maintenance component of the connection charge to use *'a shorter averaging period, or an approach based on the average rate (\$/km) rather than average cost'*
 - (v) correcting for the 'double-counting' that occurs when there are reverse flows
 - (e) sought stakeholder feedback.

⁷⁹ <https://www.transpower.co.nz/about-us/industry-information/revenue-and-pricing#pricing>.

⁸⁰ <https://www.transpower.co.nz/about-us/industry-information/tpm-development/tpm-operational-review-submissions>

- D.3 Transpower received 19 submissions on its initial consultation paper, and summarised them in terms of the following key themes:⁸¹
- (a) *‘support for the clause 12.85 review as a process to improve the operation of the current TPM without major overhaul (though views differ over what should be in scope) but desire for coherency and coordination between this work and the Electricity Authority’s clause 12.86 TPM review’*
 - (b) *‘encouragement to do more work on problem definitions, in particular to take account of real-world conditions and empirical evidence, as well as pricing theory’*
 - (c) *‘recommendation to consider additional options, particularly to address the RCPD and HAMI problems’*
 - (d) *‘encouragement to prepare robust cost-benefit analysis (CBA) for any change proposal, but especially for substantive issues e.g. RCPD and HAMI’.*
- D.4 Transpower’s second consultation paper, published in November 2014:
- (a) summarised and acknowledged feedback received on its initial consultation
 - (b) set out Transpower’s analytical approach
 - (c) provided further context on the environment in which the operational review was occurring
 - (d) revised the problem definition
 - (e) considered various possible solutions, and proposed to recommend some or all of the following solutions to the Authority:
 - (i) greatly increasing the number of peaks used in the HAMI allocator, or failing that, moving to a per-MWh allocator
 - (ii) expanding the use of ‘exceptional operating circumstances’ to include warning notices as well as grid emergencies
 - (iii) aggregating stations on a river chain for the purpose of the HVDC charge
 - (iv) derating USI generation for the purposes of the HAMI allocator
 - (v) using N=100 for all four RCPD regions
 - (vi) amalgamating the UNI, USI and LSI regions into a single RCPD region
 - (vii) adjusting the formula for the line maintenance component of the connection charge, so that it is based on average rates rather than average costs

⁸¹ https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPM-Operational-Review-Update-Paper.pdf

(viii) providing for Transpower to adjust transmission charges when a reverse flow situation occurs

(f) sought stakeholder feedback.

D.5 Transpower received 16 submissions on its second consultation paper (Table 12), and took these submissions into account when preparing its proposal to the Authority. The submissions are summarised by the Authority overleaf.

Table 12: Submissions on Transpower's second consultation

Distributors and distributor representatives	Generators/Retailers	Consumers and consumer representatives
- Counties Power - Electricity Networks Association (ENA) (on behalf of its 29 members) - Northpower - Orion - Powerco - Unison - Vector	- Contact Energy - Genesis Energy - Meridian Energy - Mighty River Power - Pioneer Generation - Trustpower	- Major Electricity Users' Group (MEUG) - Pacific Aluminium - Winstone Pulp International (WPI)

Summary of submissions on Transpower's second consultation

D.6 This summary focuses on submitters' comments on Transpower's proposals in its second consultation paper, and the structure is based on the set of consultation questions posed in that paper:

- (a) RCPD 'N' issues
- (b) RCPD region issues
- (c) HVDC charges (application of HAMI) issues
- (d) recovery of pole maintenance costs
- (e) paralleling
- (f) transition to a refined TPM
- (g) other matters

There were mixed views on RCPD 'N' issues

D.7 Of those that commented on this aspect, a number of submitters supported Transpower's proposal that N be set to 100 for UNI, and a number also supported N=100 for USI. Comments included:

- the proposed recommendations (UNI to N=100) will likely deliver efficiency gains or improvements (Vector, p.1)
- current RCPD price signal distorts consumption decisions, manifesting itself in market inefficiencies as illustrated in reports on two winter 2014 grid emergencies (Genesis, p.3)
- capacity is now generally unconstrained and the demand outlook is benign (Genesis, p.3)
- this will likely result in a less volatile RCPD allocation, leading to reduced operational costs over time for retailers (Genesis, p.9)
- setting N=100 better aligns RCPD price signals and the practicalities and economics of load management and demand response (load is typically actively managed for many more than 12 half hours) (Orion, p.2)
- if there were no transition from N=12 to N=100 and the impact of changing these signals on cost of capital was not taken into account, then parties may be reluctant to invest again on the back of any price signals provided by Transpower (Trustpower, p.3)
- given the excellent co-ordinated work that currently occurs by USI distributors, the need for transmission investment in that region might be accelerated if the RCPD signal were weakened (Trustpower, p.4)

- setting N=100 for UNI should be conditional on there being minimal quantitative impact on the allocation of transmission charges to the regions, as under such circumstances it would be preferable for the Authority to conclude its TPM review (Unison, p.3)
- any increase in N needs to be gradual and staged over a number of years to protect the interests of those who invested in response to the signal and to maintain the efficacy of price signalling as a means of influencing behaviour (Trustpower, p.3)
- equalising N across regions assists in addressing current situation where regions with a lower N face a slightly higher share of total interconnection cost than is appropriate (Trustpower, p.4)
- removing the RCPD price signal will not necessarily affect the versatility of current demand response instruments such as hot water controls (Genesis, p.3)
- other mechanisms (including nodal pricing and demand-side participation) can be used to signal and mitigate transmission capacity issues (Genesis, p.4)
- once more than 100 peaks are used the signal is too diluted
- setting N=100 is a sufficient number of peaks for regions where RCPD charges are not intended to send pricing signals (Contact, p.5)
- many systems are set to deal with 100 (Contact, p.5)
- it is worth noting that the Authority has not concluded that ACOT payments and peak-shaving by embedded generators are not in the long-term interests of consumers, nor has it concluded that they are. (Trustpower, p.3)

D.8 Some did not support the proposal, or were not yet convinced pending further analysis, and their reasons included the following:

- the proposed changes to RCPD charges are outside the scope of an operational review, and these decisions are best made by the Authority (Meridian, p.5)
- Transpower's considerations appear to have a short-term focus, yet long-term investments and pricing signals need to be considered (such as investment in hot water load control and embedded generation) (Counties Power, p.1)
- concern about adjusting one aspect of the perceived problems when the wider issues may be better addressed with a well-developed and wider ranging package of measures (NZIER for MEUG, p.2)
- there may be merit in adjusting N, but further analytical work is required to better identify cause and effects between grid usage and RCPD charges, and

taking into account an expectation of changes in consumer behaviour (NZIER for MEUG, p.2)

- increasing N to 100 for UNI in isolation could have perverse effect of allocating a greater proportion of costs to other regions away from the UNI, and without combining regions, would not remove the summer peak issue for NZAS (Pacific Aluminium, p.1)
- setting N to 100 for USI appears to be inconsistent with signalling the need to manage constraints, and needs more consideration and supporting analysis (Powerco, p.1)
- if a long-term view is taken, the increasing price signal strength needs to be weighed up against the long-term incremental transmission cost (likely to be a second 400kV line into Auckland) (Counties Power, p.1)
- a move to 100 peaks will reduce economic efficiency and have a negative impact on consumers (a lack of hot water, controlled load focussed on transmission peak avoidance and not available for other uses such as the reserves market) (Counties Power, p.2)
- investment in back-up generators would only be economic if the generators could be used to reduce transmission charges over the current 12 peaks, as operating costs to reduce 100 peaks would be too high (Counties Power, p.3)
- Transpower needs to establish whether there is any long term benefit to consumers in terms of increasing competition, reliability or efficiency from providing additional signals to reduce demand (ENA, p.5)
- increase in total transmission revenue has intensified the signal to reduce peak demand (especially in USI and UNI) and this is likely to increase incentives to reduce peak demand, but it has not been demonstrated that this would be inefficient (ENA, p.6)

There were mixed views on RCPD region issues

D.9 There were mixed views amongst those that commented on this aspect of the proposal.

D.10 Some were in support of full amalgamation, with comments that included:

- regions with the same methodology should be amalgamated (Genesis, p.10)
- amalgamation of UNI, LNI, and LSI will likely deliver efficiency gains or improvements (Vector, p.1)
- RCPD is not an appropriate tool for price signals to consumers, and more targeted demand-side control tools should be the preferred method to defer capex (Genesis, p.4)

- thought must also be given to how easily regions could be disaggregated in future as transmission capacity constraints tighten and the number of RCPD periods reduces (Trustpower, p.5)

D.11 Others favoured partial amalgamation, with USI being kept separate:

- maintaining a separate pricing region for USI is a practical transition step, but the need will reduce in the longer term (Genesis, p.4)
- if there is limited correlation between USI peak demand periods and national peak demand then it is sensible to separate USI (MRP, p.2)
- a single NI region is logical, and, although adding LSI is counterintuitive from a NI perspective, it could deliver a net gain for NZ if it removes an anomaly to facilitate productive increases at NZAS (Northpower, p.1)
- it is logical to amalgamate to take away the Tiwai abnormality where it always sets the peak in the LSI (Contact, p.6)
- live data should be made available for the amalgamated region to enable participants to gain an understanding of where the combined peak loads are occurring during the capacity measurement period (Northpower, p.2)

D.12 Others were against any amalgamation, or were not yet convinced:

- the proposed changes to RCPD charges are outside the scope of an operational review, and these decisions are best made by the Authority (Meridian p.5)
- the approach is an over-simplification of the complex issues that surround grid-connected generation versus distributed and co-generation (NZIER for MEUG, p.3)
- the impact of changing N to 100 in UNI and USI should be measured first before an additional change of amalgamating regions is implemented (Unison, p.5)
- Transpower relies on the Authority's assessment of a set of problems at the NZAS smelter resulting from a LSI regional RCPD charge, and, as this is not persuasive, a merge of UNI, LNI and LSI should not be considered at this time (NZIER for MEUG, p.3)
- there is potential for unintended outcomes if LNI and LSI are merged (e.g. dominance of Auckland load in driving 100 peaks, unforeseen responses to new measurement and pricing signals) (NZIER for MEUG, p.3)
- pricing regions should reflect grid configurations and the areas where there is common ability to manage the drivers of network investment (Orion, p.3)
- redefining or amalgamating regions should not be done just because there is no medium term need for investment (that is what N is for) or because there

may be issues in one region (e.g. Tiwai). Orion further commented that Tiwai's influence on LSI RCPD is problematic and may be leading to inefficient outcomes for smelter operation, but that Tiwai issues should be addressed by a bespoke arrangement that involves removing Tiwai from LSI and separately assessing an appropriate charge or chargeable quantity (Orion, p.3)

- amalgamation of UNI, LNI and LSI would reintroduce for USI the unfairness associated with existing split of N=12 and N=100 regions (Orion, p.3)
- would enable participants to act to reduce demand in response to a more aggregated signal that may not be correlated to their region, producing demand forecasting challenges and risk of over/under response. (MRP, p.2)

A MWh approach was favoured by many who expressed views on application of HAMI issues

D.13 Transpower invited comments on the effects of the existing HAMI charge. Replies included:

- recent significant improvements to transmission capacity mean that going forward the limitation on offered generation capacity is solely due to the HVDC charging regime (Contact, p.7)
- the transmission charge does appear to cause existing generators to withhold capacity (ENA, p.6)
- the proposed MWh charge on net injection volumes is the simplest solution (Pioneer, p.2)
- HAMI charge acts as a disincentive to peaking generation but also inflexible intermittent generation with relatively low load factors (e.g. wind) (Trustpower, p.5)
- unconvinced that the HAMI charge has resulted in reduced generation capacity expansion, as other factors (access to fuel or resources for generation, demand forecasts, consumer growth patterns) are more likely to be relevant (Genesis, p.11)
- likely to have encouraged less-efficient dispatch decisions by SI generators (Genesis, p.11)
- the derating of USI generation in terms of the HAMI charge appears to be ad hoc, and caution is therefore warranted (ENA, p.6)

D.14 There was little support for Transpower's (tentative) proposal to recommend that the Authority consider changing the HVDC charges from HAMI to a diluted HAMI.

D.15 Submitters that did not support a diluted HAMI charge included the following comments:

- it distorts generation offers in the market (Genesis, p.2)
- it will not result in a material change to generation offer behaviour and therefore will not resolve the ensuing security risks and price volatility during times of low committed thermal capacity (these concerns can be overcome with a MWh approach) (Contact p.8)
- a very large N value would introduce a level of complexity into the market that may not be justified (Trustpower, p.6)
- it is difficult to model (Genesis, p.5)
- a piecemeal approach to HVDC issues is not appropriate, and HVDC charging should be dealt with by the Authority as part of its overall review (Meridian p.10)
- Transpower's analysis to date is not sufficiently robust to determine an optimal value for N (Meridian, p.10)
- a diluted HAMI charge will not result in a material change to offer behaviour (Contact, p.1)
- there has not been a full consideration of available options (e.g. removing the distortion created by having a separate HVDC charge) (Meridian, p.10)
- potential for gaming still exists (Genesis, p.5)
- risk of unintended consequences due to complexity (Genesis, p.5)
- a MWh charge is preferable to a diluted HAMI (see below) (Genesis, p.2)

D.16 A number of submitters supported a MWh charge over a HAMI charge or diluted HAMI charge. Comments included:

- benefits relative to HAMI or diluted HAMI are that it would enable full capacity to be offered at peak periods, increase security for Transpower, reduce price volatility for purchasers during capacity shortfalls, and avoiding unnecessary spill of water or wind (Contact, p.1)
- a MWh charge is easier to implement and will lead to lower levels of distortion of consumer and generation decisions (Genesis, p.2)
- likely to provide the optimal mix of efficiency, benefits to wholesale prices, transparency and simplicity (Trustpower, p.6)
- it would reduce the prices offered for previously underutilised peaking generation capacity in SI (or ensure that capacity was offered more often (Trustpower, p.6)
- it enables consistent treatment of all SI generators without the need to make allowances for river chains (Genesis, p.5)

- short-term distortions from a MWh allocation will be less than those from a MW allocation, however, significant dynamic inefficiencies associated with the allocation of HVDC charges to SI generators will remain (e.g. major deterrent to new SI grid connected generation, impediment to maximising utilisation of SI renewable generation resources) (Meridian, p.4)
- could provide a short term arrangement (5 year cumulative MWh charge) pending completion of the Authority's full review of transmission charges (Meridian, p.10)
- minimal impact on generation investment decisions (Genesis, p.6)
- introduces a price-floor for SI generation, but this is likely to be minimal and is unlikely to affect consumer decisions (Genesis, p.5)
- the possibility (raised by Transpower) that moving to a MWh charge could increase overnight process is not a material issue (Contact, p.2)

D.17 Some did not support the proposal or were unconvinced at this time, and their reasons included the following:

- concerns with assumptions, the estimates of costs and benefits, and aspects of the analytical approach (WPI, p.1)

D.18 Some submitters commented on the proposed discount for USI generation. Comments included:

- all SI generators should be treated consistently under any allocation mechanism, and there is no evidence to suggest otherwise (Genesis, p.6)
- a USI discount amounts to a cross-subsidy of USI generation by other SI generators, and market-based mechanisms should instead be explored, targeted to the specific capacity issues (Genesis, p.6)
- this diverges from the current TPM principle that the HVDC charge is applied to SI grid-connected generation (Contact, p.3)
- this is ad hoc, inadequately justified and open to legal challenge as it is inconsistent with the relevant pricing guideline (Powerco, p.2)
- such a fundamental change to the HVDC charge should only be considered as part of the Authority's review of the methodology (Powerco, p.2)
- Transpower should not use transmission charges to carry out a central planning role (Meridian, p.2)
- reducing HVDC USI charge for a HVAC purpose is beyond the scope of an operational review (Contact, p.3)

D.19 Other comments on HAMI included the following:

- Transpower should consider further the option to change the TPM to allow river chain aggregation as a permanent measure (Contact, p.10)

- supportive of river chain aggregation as a permanent measure although due consideration should be given to approval in each case (MRP, p.3)

Strong support for proposed approach to recovery of maintenance costs

- D.20 Transpower invited comments on the appropriate basis for recovering pole maintenance costs. There was a reasonable measure of support for recovery on an average \$/km basis than an average cost basis. Responses included:
- this is a preferable approach to reducing the number of years over which the cost is averaged (ENA, p.6)
 - this better reflects actual connection asset maintenance costs (Powerco, p.2)
 - the problem being addressed is a direct result of the high rate of connection asset divestment, not envisaged when the TPM was originally developed (Powerco, p.2)
 - a cost reflective allocation is supported (Meridian, p.11)

Strong support for paralleling proposal

- D.21 Transpower invited comments on its proposal to amend the TPM to address paralleling issues. Most submitters did not comment on the paralleling proposal while some supported the proposal. Comments included:
- the circumstances need to be genuine (Meridian, p.11)
 - the change appears sensible (Genesis, p.12)
 - Transpower's paralleling proposal to tie GXPs where there is a through-feed via a distribution network in parallel to the transmission network is reasonable (ENA, p.6)
 - a permanent provision that deals with the calculation of capacity factors where there is a through-feed via an electricity distribution business's distribution network in parallel with the transmission network is warranted (Vector, p.1)

Mixed views on transition to a refined TPM

- D.22 Of those who commented, most favoured the changes being introduced quickly, as proposed by Transpower. Comments included:
- there are little or no costs to generators introducing the diluted HAMI or MWh charge as quickly as possible (Genesis, p.14)
 - a phase-in period is unnecessary (Contact, p.10)

- for HVDC charges allocation on a 5-year MWh basis, it would be reasonable to start the capacity measurement period on 1 September 2015 given the stability of the percentages (Meridian, p.11)
 - no transition is necessary to the extent that none of the changes come close to causing rate shock (Orion, p.7)
 - a quick transition will deliver the benefits earlier (Genesis, p.14)
- D.23 Some considered there should be a transitional arrangement to phase in changes to RCPD:
- the proposal will impact on operational costs, particularly for embedded and notionally embedded generators who have made good faith investments based on current arrangements (MRP, p.4)
- D.24 Other comments on transition issues included:
- it is fine for the change in N=12 to 100, providing that there remains adequate lead-in time between the final decision being announced and the implementation date (Unison, p.7)
 - it is less likely that a transition period would be required for HVDC link charges as it appears these have traditionally deferred investment rather than encouraged it (Trustpower, p.9)
 - if HVDC charges were to be allocated on a 5-year MWh basis, it would be reasonable to start the capacity measurement period on 1 Sept 2015, although given the stability of the percentages, 1 Sep 2014 could be acceptable (Meridian, p.11)
 - the measuring period should be unchanged at the start of Transpower's implementation (i.e. the current year plus four previous years) as there is no reason to change from the status quo. (Contact, p. 10)

Other matters were raised in submissions

D.25 Other comments raised in submissions included the following:

- aspects of the Transpower proposal are outside the scope of an operational review which should be limited to operational and technical matters (Meridian, p.1)
- two simultaneous rounds of substantive reform to the TPM create instability and uncertainty for investors (Meridian, p.1)
- concern about how Transpower's operational review will be integrated with the Authority's ongoing review of the TPM guidelines (ENA, p.7)
- the issues Transpower has identified are controversial and have the potential to 'not' complement the Authority's efforts to improve the TPM overall (NZIER for MEUG, p.4)
- the likely disruption and cost of implementing the proposed changes does not appear to be warranted because even if the suggested benefits were assured, they are likely to be short-lived assuming the Authority's proposed changes follow within a few years (WPI, p.1)
- the transmission cost allocation mechanism should be reviewed periodically (e.g. five yearly or if specified triggers reached) to ensure it reflects current market situations and avoids unintended consequences (Genesis, p.2)
- period reviews should be limited in scope (Orion, p.7)
- the existing TPM has maintained its durability (i.e. been long lasting) through inertia of the regulatory process, but durability per se is not necessarily a desirable trait (Pacific Aluminium, p.7)
- changing $N > 100$ and amalgamating USI pricing region should be specifically considered in the next scheduled operational review of transmission pricing methodology settings (Genesis, p.4)
- an additional criteria is required in Transpower's assessment criteria to ensure options are non-distortionary to producer and consumer decisions (Genesis, p.3)
- most distributors have been using demand response to defer transmission investment for decades (i.e. predating RCPD) leveraging long term relationships with consumers who themselves have made long-term investments (Orion, p.2)
- efficiency gains from the proposed operational changes with the current TPM guidelines might be equivalent to, or even exceed, the net benefit of the Authority's TPM proposals (excluding HVDC), especially given the associated large implementation costs (Pioneer, p.1)

Appendix E The four components of Transpower's proposal that are being consulted on

[Please refer standalone document '[Appendix E of the Transpower TPM consultation paper – the 4 components being consulted on.docx](#)']

Appendix F Attachment B to Transpower's proposal: *'Background and supporting information'*

[Please refer standalone document '[Appendix F of the Transpower TPM consultation paper – attachment B to Transpower proposal background & summary.docx](#)']

Appendix G Indicative estimates of LRMC

- G.1 This Appendix provides the derivation of estimates of the regional LRMC of transmission, which are:
- (a) \$10/kW per year in the UNI
 - (b) \$15/kW per year in the USI
 - (c) \$0/kW per year in the LNI and LSI.
- G.2 The LRMC of transmission indicates the cost of providing additional transmission capacity to serve an increase in regional peak demand. In other words, the meaning of these estimates is that an enduring 1 kW increase in regional peak demand is estimated to cause a transmission investment cost that is equal (in present value terms) to:
- (a) an annuity of \$10 per year (in real terms), if the increase is in UNI peak demand
 - (b) an annuity of \$15 per year (in real terms), if the increase is in USI peak demand
 - (c) nil, for an increase in LNI or LSI peak demand. In other words, there is no expectation that increased peak demand in these regions would drive a need for transmission investment.
- G.3 These estimates are used:
- (a) in the design of the interconnection charging option that is ‘a combination of a regional LRMC-based charge and a per-MWh charge on gross load’, which is discussed in Sections 4.5 and 4.6 and Appendix I of this paper
 - (b) as the basis of the ‘low transmission deferral value’ scenario that is used in the CBA in Appendix I of this paper.
- G.4 Appendix I also incorporates a ‘high transmission deferral value’ scenario, which uses LRMCs that are higher than those in this Appendix. The ‘high transmission deferral value’ scenario could be valid if the need for substantial new transmission investment to meet peak demand was substantially more pressing than is assumed in this Appendix.
- The form of LRMC used
- G.5 As noted in the Authority’s LRMC working paper, there are three main approaches to calculating LRMC:⁸²
- (a) Marginal incremental cost (MIC), which considers how future costs will change as a result of a permanent change in demand

⁸² <https://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c13677>

- (b) Long-run incremental cost (LRIC), which calculates the annualised cost of the next proposed investment and divides this by the permanent increment in demand
- (c) Average incremental cost (AIC), which calculates the additional capital and operating expenses over the planning period required to meet a permanent increase in demand (over and above forecast increases in demand) for the planning period.

G.6 As will be set out in the Authority's options working paper, the Authority prefers the MIC approach over LRIC or AIC – because MIC is most consistent with providing efficient price signals.

G.7 Therefore, the LRMC estimates in this Appendix are based on the MIC approach.

G.8 For a given transmission upgrade U that may be required to provide capacity into a region R, MIC is calculated (in \$/kW terms) as the present value of a year's deferral of U, divided by the expected annual increment in peak demand in R.

G.9 MIC is then:

- (a) summed over all transmission upgrades U that may be required, and
- (b) converted into \$/kW *per year* terms by dividing by an annuity factor of 10.5.

Key input assumptions

G.10 The LRMC estimates in this Appendix are based on a hypothetical 2017 scenario. LRMC is calculated over a ten-year horizon, from 2017 to 2027. An 8% real discount rate is used.

G.11 Estimation of LRMC using the MIC approach involves forming a view on:

- (a) the cost of transmission investment required to meet increases in regional peak demand (or congestion)
- (b) the increase in regional peak demand (or congestion) that will trigger the investment
- (c) the length of time until the investment is expected to be required.

G.12 In practice, the LRMC-based charge would be calculated based on information about possible transmission investments, as published in Transpower's planning documents (such as the Annual Planning Report).

G.13 For the purpose of this analysis, the Authority has prepared a list of possible future investments (Table 13). The Authority emphasises that this list is not intended to accurately predict the course of future transmission investment. Rather, it is intended to present a somewhat plausible view of how the investment landscape might look in the 2017 scenario, for the purpose of the modelling work in this paper.

Table 13: List of possible future investments anticipated in a hypothetical 2017 scenario – used for the purpose of preparing indicative estimates of LRMC

Region	Investment that might be triggered by growth in regional peak	Explanation	Modelled cost (\$M real)	Modelled anticipated commissioning year	Modelled increase in regional peak demand to trigger investment (MW)
UNI	Upper North Island voltage stability	Mixture of static and dynamic reactive support, driven by UNI load growth.	60	2024	550
	Third cable from Brown Hill to Otahuhu	Investment to manage peak demand in the UNI - was a modelled project in the NIGU GUP.	60	2027	700
	Second 220 kV PAK-PEN circuit	Investment to manage peak demand in the UNI - was a modelled project in the NAaN GUP.	60	2027	700
LNI	None				
USI	Upper South Island grid upgrade - stage 2	Investment to manage peak demand in the USI. May include new switching stations (e.g. Orari) between the Waitaki Valley and Christchurch.	58	2020	120
	Upper South Island voltage stability	Mixture of static and dynamic reactive support, driven by USI load growth.	50	2027	350
LSI	None				

Results

- G.14 Based on the input assumptions above, LRMC (in \$/kW terms) is calculated as:
- (a) \$100/kW for UNI, which is the sum of:
 - (i) \$36/kW for UNI voltage stability
 - (ii) \$32/kW for the third cable from Brown Hill
 - (iii) \$32/kW for the second circuit from Pakuranga to Penrose
 - (b) nil for LNI
 - (c) \$145/kW for USI, which is the sum of:
 - (i) \$92/kW for stage 2 of the USI grid upgrade
 - (ii) \$53/kW for USI voltage stability.
 - (d) nil for LSI.
- G.15 Converting into \$/kW per year terms, and applying rounding, yields indicative estimates of:
- (a) \$10/kW per year in the UNI
 - (b) \$15/kW per year in the USI
 - (c) \$0/kW per year in the LNI and LSI.
- G.16 These estimates may be:
- (a) underestimates, if the need for transmission in response to regional peak demand is more than is shown in Table 13, or
 - (b) overestimates, if the need is less.

Appendix H The interconnection charge components considered are consistent with Guideline 12

- H.1 Guideline 12 of the Guidelines states that '*Charges for existing and new interconnection assets should be on a postage stamp basis. This is similar to the current interconnection charges.*'
- H.2 In its September 2004 consultation paper that included proposed guidelines for Transpower's transmission pricing methodology, the Electricity Commission stated that:
- "Grid charges are called "postage stamp charges" when charges are not based on the distance or location of grid users or customers. The same charge rate applies regardless of whether power is conveyed between generators and consumers in the same location or conveyed from one end of the country to the other."*⁸³
- H.3 That is, the essence of postage stamp charge is that the rate remains constant.
- H.4 In analysing Transpower's proposed transmission pricing methodology, in a provisional response paper on 11 April 2007, the Commission stated that an alternative proposal put forward by Strata breached the postage stamp requirement by creating multiple interconnection rates. The Commission stated that the Strata proposal therefore did not conform with Guideline 12. The Commission noted that, in contrast, the proposed transmission pricing methodology used a varying basis of demand, but then applied a standard postage stamp rate to derive individual customer charges.⁸⁴
- H.5 The Authority is comfortable that it remains appropriate to interpret Guideline 12 as requiring the same interconnection rate to apply in respect of all interconnection assets for all interconnection consumers, but that the basis of demand may be varied/variable.
- H.6 The interconnection charge options evaluated in Section 4.6 are:
- (a) Transpower's proposal – RCPD with N=100 in all four regions
 - (b) the status quo – RCPD with N=12 in UNI and USI and N=100 in LNI and LSI
 - (c) RCPD with N=500 in all four regions
 - (d) a per-MWh charge on gross load
 - (e) an option that is a 50-50 mix of the status quo and a per-MWh charge on gross load

⁸³ <http://www.ea.govt.nz/dmsdocument/3863>, at footnote 1.

⁸⁴ <http://www.ea.govt.nz/dmsdocument/17454>, at paragraph 6.2.12(a).

- (f) an option that is a combination of a regional LRMC-based charge and a per-MWh charge on gross-load.

- H.7 This Appendix explains how all these options are consistent with Guideline 12.
- H.8 The option that is most clearly consistent with Guideline 12 is the per-MWh charge on gross load. Under this option, each of Transpower's offtake customers would pay a charge that was the product of their total gross load and a per-MWh rate that was constant across all offtake customers. (The per-MWh rate would be in the order of \$20/MWh.)
- H.9 The three RCPD options, including the proposal, the status quo, and an option with N=500 in all three regions, are also consistent with Guideline 12. Under these options, each of Transpower's offtake customers would pay a charge that was the product of their RCPD quantity (in kW) and a per-kW rate that was constant across all offtake customers. (The per-kW rate would be on the order of \$120/kW.)
- H.10 While the rate remains constant, there can still be locational differentiation under a postage stamp charge. Under the status quo, this differentiation is achieved by using different values of N in different regions.
- H.11 The option that is a 50-50 mix of the status quo and a per-MWh charge on gross load is also consistent with Guideline 12. Under this option, each of Transpower's offtake customers c would pay a charge that was the product of a per-kW rate that was constant across all offtake customers and the following expression:

$$0.5 \left(RCPD_c + MWh_c \frac{\sum_{c'} RCPD_{c'}}{\sum_{c'} MWh_{c'}} \right)$$

where $RCPD_c$ is customer c 's RCPD quantity (in kW) and MWh_c is customer c 's gross load (in MWh).

- H.12 The option that is a combination of a regional LRMC-based charge and a per-MWh charge on gross-load is also consistent with Guideline 12. Under this option, each of Transpower's offtake customers c would pay a charge that was the product of a scalar that was constant across all offtake customers and the following expression:

$$0.5 \left(RCPD_c \cdot LRMC_c + MWh_c \frac{\sum_{c'} RCPD_{c'} \cdot LRMC_{c'}}{\sum_{c'} MWh_{c'}} \right)$$

where $RCPD_c$ is customer c 's RCPD quantity (in kW), $LRMC_c$ is the estimated long-run marginal cost of transmission into the region in which customer c is located (in \$/kW) and MWh_c is customer c 's gross load (in MWh).

Appendix I CBA of interconnection charge components

- I.1 This appendix describes the CBA undertaken by the Authority in relation to:
- (a) Transpower's proposal to alter the interconnection charge by setting N=100 for all four regions when assessing each customer's contribution to regional coincident peak demand (RCPD)
 - (b) alternative interconnection charge options (including some that were considered by Transpower, but not assessed in quantitative terms).
- I.2 As discussed below, the CBA adopts assumptions in some areas because there is limited public data available on certain issues. In these areas, the Authority has published its explicit assumptions and seeks information from submitters on whether these are reasonable, or if not, what information can be used to improve the assumptions.
- I.3 The Authority is also making the CBA spreadsheet available on its website so submitters can perform their own sensitivity analysis on the CBA if they wish.⁸⁵

Nature of benefits and costs considered in CBA

- I.4 Based on the existing charging methodology, the interconnection charge in 2017/18 is estimated to be around \$110/kW/yr, or approximately \$19,000/MWh in variable cost terms for parties in the UNI and USI.
- I.5 This signal may encourage transmission customers to undertake inefficient peak avoidance activity. This activity is intended to lower a customer's share of total transmission charges, but which is expected to produce little or no economic benefit from reduced transmission costs – i.e. because there is no capacity constraint.
- I.6 The peak avoidance activity may involve excessive use of, or further investment in, load management or embedded backup/peaking generation. The expected benefit from alternative interconnection charges is a reduction in inefficient peak avoidance activity.
- I.7 Another potential benefit is that alternative charging methodologies may reduce premature or misdirected investment in embedded generation that is not specifically directed at peak avoidance. For example, the current interconnection charge equates to around \$18/MWh in average terms over a year. This price signal could bring forward the timing of investment in embedded smaller scale hydro or wind generation.
- I.8 In terms of potential costs, it is possible that altering the interconnection charge may also encourage some new instances of inefficient load management or embedded back up/peaking generation. This could occur if parties expand their

⁸⁵ CBA for RCPD N=100 <http://www.ea.govt.nz/dmsdocument/19324> (zip file)

peak avoidance activity across a larger number of time periods in response to increasing N from 12 in the UNI and USI.

- I.9 Another potential cost is that there may be transmission deferral benefits that are occurring under the current arrangement that will be foregone under an alternative interconnection charging regime.
- I.10 Finally, the CBA considers the potential for so-called 'deadweight' losses to occur.⁸⁶ Such losses could arise if some electricity users were to reduce their ongoing demand (or cease usage altogether) solely in response to a reallocation of interconnection charges among transmission customers.

Estimation of 'peak avoidance' effects

- I.11 The analysis considers the effect of different interconnection charge regimes on a range of 'peak avoidance' technologies. A range of technologies is considered because each has differing cost structures. Interconnection charges regimes can have differing impacts on each technology because of their diverse cost structures.
- I.12 For example, some lower cost demand response (e.g. water heating) is likely to be operated up to its current limits and may not be significantly influenced by changes in the RCPD regime. However the operation of backup generation and more costly demand management could be significantly affected by the interconnection charge regime.
- I.13 The CBA considers the following technology types when estimating peak avoidance effects:
 - (a) low avoidable fixed costs and low variable costs - such as existing embedded backup or peaking generation with a short run marginal cost (SRMC) of \$300/MWh (around the cost of diesel)
 - (b) low avoidable fixed costs and medium variable costs - such as existing lower cost load control with an SRMC of \$500/MWh
 - (c) low avoidable fixed costs and higher variable costs - such as existing load control with an SRMC of \$1000/MWh
 - (d) low avoidable fixed costs and high variable costs - such as existing load control with an SRMC of \$3000/MWh
 - (e) high avoidable fixed costs and low variable costs – such as new diesel-fired backup generation with SRMC of \$300/MWh.
- I.14 The analysis assumes on-going fixed costs for existing technologies of \$20/kW/yr. This reflects the fact that maintaining load control capability and backup

⁸⁶ Deadweight loss refers to a situation where the optimal level of production and consumption of a good/service does not occur because the decisions of producers and consumers are distorted by some factor. .

generation will incur some cost, but this is expected to be materially lower than the cost of new investment.

- I.15 The analysis also considers the impact of different interconnection charge regimes on incentives to invest in new backup/peaking generation. In this case, the inefficiency would take the form of premature investment in peaking/backup generation that is brought forward simply to avoid interconnection charges.
- I.16 If such investment-related costs arise in a scenario, the assumption is that peaker/backup investment will be brought forward from year 15 to year 5. Although premature investment might occur at an earlier point, this appears less likely given the current and projected capacity margin.
- I.17 The avoidable fixed cost for new diesel-fired generation is assumed to be \$100/kW/yr. This compares with typical estimates of approximately \$125-145/kW/yr for a new stand-alone peaking/backup generation plant. Some reduction is allowed on the basis that such generation is likely to yield benefits in addition to avoided interconnection charges and spot market effects. In particular, backup plant is typically partly justified as protection against distribution outages and to protect very high value load.
- I.18 The analysis recognises that peak avoidance activity directed at RCPD periods will not have a 100% success rate. For example, Transpower's analysis assumed that parties would need to operate in 48 trading periods in order to 'hit' the top 12 RCPD periods (a 25% success rate). The Authority's analysis adopts the same assumption for scenarios where $N=12$.⁸⁷
- I.19 As the value of N increases, the success rate is expected to rise because it is easier to forecast the top 100 demand periods than the top 12 periods. The Authority's analysis assumes a success rate of 67% for $N=100$ and 91% for $N=500$.
- I.20 For each technology type and transmission region, an assumption is required about the volume of resource that is potentially available. For example, the analysis needs to consider the volume of backup generation with an SRMC of \$300/MWh in the lower North Island in order to assess how this is affected by different interconnection charge options.
- I.21 Unfortunately, there is very little public information available on this issue, especially at a regional level. The Authority has therefore adopted assumptions based on the limited data that is available (Table 14), and seeks information from submitters to refine these assumptions.

⁸⁷ This applies to the UNI. For the USI the RCPD curve is virtually flat from $N=100$ to $N=12$ and so in this case it is assumed that at the margin, peak avoidance technologies would have to operate for at least 100 periods. This means that a change from $N=12$ to $N=100$ is likely to have very little impact in that region.

Table 14: Peak avoidance resource available in each region (as % of peak load)

Technology	UNI	USI	LNI	LSI	SRMC \$/MWh
	% of 2014 Peak demand				
Existing backup generation	1.0%	1.0%	0.5%	0.1%	\$300
Existing load control 1	1.5%	1.5%	1.5%	0.4%	\$500
Existing load control 2	0.8%	0.8%	0.5%	0.1%	\$1,000
Existing and new load control 3	0.5%	0.5%	0.0%	0.0%	\$3,000
New backup generation (next 5 yrs)	0.0%	0.0%	0.0%	0.0%	\$300
New back up generation (in year 5-15)	1.0%	0.3%	1.0%	0.1%	\$300

- I.22 The analysis estimates the impact of alternative interconnection charge regimes on the incentives to use, or invest in, each peak avoidance technology type. This was determined by considering the gross margin each technology type would be expected to earn in a year. If gross margin was positive, the technology would operate, and vice versa.
- I.23 Gross margin was defined as the expected 'revenue' from avoided interconnection charges, plus expected spot market revenues (from operating when spot prices were greater than SRMC), minus the expected cost of 'trading losses' incurred when operating to meet the RCPD peaks and wholesale prices were less than SRMC. The estimates for operating losses and market revenues were based on actual data from recent years.
- I.24 The efficiency loss was the dollar difference between the SRMC of peak avoidance and spot prices (where these were higher), multiplied by the volume of response.

Estimation of effects related to embedding baseload and intermittent generation

- I.25 Under the status quo, embedded baseload and intermittent generation (e.g. renewable wind and geothermal) may capture value from avoided cost of transmission (ACOT) over the top 12 or 100 regional peaks. This activity can be expected to have a success rate (as defined above) of around 70-100% (depending on technology) of the average annual MW generation. This could equate to \$13 to \$18/MWh additional ACOT revenue. This could result in economic loss arising from embedded generation being built ahead of cheaper grid connected plant and/or from bringing forward investments ahead of the time justified by wholesale prices alone.
- I.26 It is difficult to estimate the extent of this economic loss, but it could range between zero and the full additional ACOT revenue. It is unlikely that there will be

a significant impact for the next 5 years, but it may have an impact for the following 5 years. The quantity of new investment is also difficult to determine but could plausibly be in the range of 0 to 350 GWh/yr.

- I.27 In the absence of better information, the Authority has estimated the potential dynamic economic losses at 50% of the ACOT revenue for 0 to 350 GWh over years 5 to 15.
- I.28 The ACOT revenue for embedded non-peaking generation will vary between options. It may be slightly higher than the status quo with N=100 or N=500, and zero for the option with a per-MWh charge on gross load.

Estimation of deadweight loss effects

- I.29 Deadweight losses may arise if some ongoing reduction in demand were to occur purely in response to the reallocation of interconnection charges among customers. This effect is only considered to be potentially significant for large scale loads with elastic demand (as might be the case for export exposed industries such as pulp and paper, steel, and aluminium production).
- I.30 It is considered less likely to occur for mass market customers because they are likely to already face interconnection charges in a form that is highly variabilised by their distribution company and/or retailer.
- I.31 Some larger customers with flexibility to alter the timing of their operations may be in a position to shift their load to avoid RCPD measurement periods. This may be more difficult as the value of N increases, but appears feasible under N=12, N=100 or N=500 regimes for customers with flexibility to rearrange their production (as evidenced by some users in the LNI).
- I.32 If the charge was based per MWh then it would not be possible to avoid the charge by rearranging production, and so it is possible that total production/demand might become uneconomic for some users. Some of these industries have embedded generation, and so a charge based on per MWh gross demand may also reduce their international competitiveness.
- I.33 The CBA considers different sensitivity cases for the price elasticity of demand between -0.35 to -1.5. This range is somewhat more price responsive than typically used to consider changes in total electricity demand.⁸⁸ Its use in this CBA is judged to be appropriate because it relates to a relatively price sensitive sub-segment of demand that is exposed to international competition, rather than total New Zealand electricity demand.
- I.34 The quantities of potentially elastic industrial demand in the CBA are assumed to be basic ferrous metals (500-1500 GWh), pulp paper and wood processing (1500-3500 GWh) and basic non-ferrous metals (4000-6000 GWh). These estimates are based on published demand data for these sectors.

⁸⁸ For example, the Electricity Commission used -0.26 in some of its analysis of policy proposals.

Estimation of transmission cost effects

- I.35 Interconnection charge regimes may affect the peak load in a region by altering the use of load control or embedded generation. This may in turn alter the time when new transmission (and potentially distribution) investment costs are incurred. The potential for these effects to occur is not known with certainty, and is expected to vary across the regions.
- I.36 To address this issue, the CBA considers two scenarios for transmission deferral effects as set out in Table 15:
- (a) the 'low transmission deferral value' scenario is consistent with the analysis in Appendix G
 - (b) the 'high transmission deferral value' scenario is not consistent with the analysis in Appendix G, but could be valid if the need for substantial new transmission investment to meet peak demand was substantially more pressing than is assumed in Appendix G.

Table 15: Transmission timing effect scenarios

	LRMC of transmission (\$/kW/year)			
	UNI	USI	LNI	LSI
Low transmission deferral value	10	15	0	0
High transmission deferral value	80	80	40	40

- I.37 These rates should be interpreted as a discounted average over the next 15 years.
- I.38 To understand how sensitive the CBA results are to this issue, sensitivity cases have been compiled where alternative weightings are applied to these scenarios.
- I.39 These rates are applied to the expected increase in regional peak demand as a result of MW reductions in peak avoidance activity expected under each pricing option.
- I.40 The CBA also accounts for the increased uncertainty in regional peak demands that may arise with options that provide little or no signal to control net load at time of regional peak (e.g. the N=500 or per-MWh options). This is accounted for by scaling up the expected increase in the RCPD to one that is relevant to transmission investment expenditures (e.g. P90 or P50 half hourly peak). This adjustment is only applied to the N=500 and per-MWh options. The extent of the effect is difficult to determine without significant work, but could correspond to an additional 20 to 40% on the reduction in peak avoidance MW (i.e. around 0.2% to 1.0% of total regional peak demand).

Options that have been assessed

- I.41 The CBA assesses the following options, relative to the status quo:
- (a) the Transpower proposal to set $N=100$ in all four regions
 - (b) a per-MWh charge on gross load
 - (c) a RCPD option with $N=500$ in all four regions
 - (d) an option that is a 50-50 mix of the status quo and a per-MWh charge on gross load
 - (e) an option that is a combination of a regional LRMC-based charge and a per-MWh charge on gross-load (as described in Section 5.5).

Results of CBA

- I.42 The CBA assesses costs and benefits in present value terms, discounted at 8% over a 15 year timeframe.
- I.43 Given the uncertainty around some key assumptions, a range of sensitivity cases were considered in the CBA. The cases are as follows.
- Base case – this case assumes a reasonable likelihood of new transmission investment being required, absent any clear peak avoidance signal.⁸⁹ Elastic industrial load is assumed to be 9,000 GWh with a price elasticity of -1.5, and it is assumed that interconnection charges have no impact on embedded baseload and intermittent new generation investment.
 - Case A – this is the same as the base case, except that it assumes a lower likelihood of transmission investment being required in the absence of a clear peak avoidance signal, and that inefficient investment in 350 GWh/yr of new embedded baseload and intermittent generation beyond year 5 may occur, depending on the interconnection charge price signal.
 - Case B – the same as Case A, except that elastic industrial load is assumed to be somewhat lower (7,000 GWh, c.f. 9,000 GWh in the Base Case) and less sensitive to price changes.
 - Case C – the same as Case B, except that it assumes a further lowering of the likelihood of transmission investment being required in the absence of a clear peak avoidance signal, and industrial load has a further reduction in its price sensitivity.

⁸⁹ This case also assumes that substantial removal of any incentive to manage regional peaks within the top 12 or 100 periods will result in a significant increase in the variability of the P50 or P90 half hour peak measure, with a flow-on impact on new transmission investment costs as discussed in A22 above.

- Case D – the same as Case C, except that there is no likelihood of substantial transmission investment being required in the absence of a clear peak avoidance signal.

- I.44 At this stage the Authority takes no view as to the relative probabilities of the base case and the four sensitivity cases. The Authority is not necessarily asserting either that the base case holds, or that any one of the five cases considered holds. The cases are merely chosen in order to illustrate how the conclusion depends on the input assumptions.
- I.45 Table 16 sets out the results of the analysis for the base case and sensitivity cases, and summarises the key assumptions for each case. The preferred option under each set of assumptions is marked with a grey box.

Table 16: Results of CBA

	Base	Case A	Case B	Case C	Case D
<u>Option</u>					
Status Quo (N=12 UNI/USI, N=100 LNI/LSI)	\$0	\$0	\$0	\$0	\$0
a) N=100 all Regions	\$5	\$6	\$6	\$17	\$10
b) N=500 all Regions	\$3	\$24	\$24	\$46	\$47
c) 50:50 Gross MWh, Status Quo	\$4	\$12	\$30	\$49	\$43
d) LRMC & Gross MWh	-\$88	-\$61	\$4	\$48	\$48
e) Gross MWh	-\$108	-\$71	\$2	\$53	\$58
<u>Assumptions</u>					
Total NZ elastic industrial load (GWh)	9,000	9,000	7,000	7,000	7,000
Elasticity for deadweight loss calc	-1.50	-1.50	-0.75	-0.35	-0.35
% weighting on high cost Tx avoidance	33%	25%	25%	10%	-
Embedded renewables brought forward (GWh)	-	350	350	350	350

(Note: The figures shown are expected net economic benefits, relative to the status quo option. They are expressed in millions of dollars, present value over 15 years. An 8% real discount rate is used.)

- I.46 The results indicate that under the base assumptions, the charging option with N=100 in all regions (Transpower's proposal) is preferred. However, the results are quite sensitive to some assumptions. In particular, it is necessary to believe that a strong peak avoidance signal is required to defer transmission investment costs.
- I.47 If increased transmission investment is seen as unlikely in the absence of a significant peak avoidance signal (i.e. there is substantial headroom for load

growth), then other charging options are expected to be preferable because they will cause less inefficient peak avoidance activity.

- I.48 If there is significant potential for deadweight losses to occur (Case A), then increasing N to 500 in all regions is expected to be the preferred option. This should reduce the expected level of inefficient peak avoidance activity motivated by the current regime, but without a material risk of deadweight loss.
- I.49 On the other hand, if there is little or no opportunity to benefit from transmission investment deferral and there is a low likelihood of deadweight costs being incurred (Cases C and D), then options that have a sizeable proportion of interconnection costs recovered via per-MWh charges are likely to be preferred.
- I.50 Finally, if there is a moderate risk of deadweight loss and little or no opportunity to benefit from transmission deferral (Case B), then a hybrid of per-MWh and N=100 is preferred.