Summary of submissions

Transpower's proposed variation to the Transmission Pricing Methodology – consultation paper

August 2015

Introduction

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

2 Transpower proposed a variation to the TPM, with a number of components, in February 2015. Subsequently, in March, Transpower added further components to the variation.

3 The Electricity Authority (Authority) considered the proposed variation and, in April 2015, published a consultation paper regarding four of the components, titled 'Transpower's proposed variation to the Transmission Pricing Methodology'.[1] The consultation paper is available on the Authority's website at http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/consultations/#c15231.

4 The consultation paper:

(a) explained three problems identified by Transpower

(b) set out four amendments to the Code to address the problems identified, corresponding to four components of Transpower's proposal

(c) sought feedback on the proposal

5 The problems identified in the consultation paper were that:

(a) the regional coincident peak demand (RCPD) allocation of the interconnection charge[2] 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

(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[3] is not clear enough

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1 The Authority subsequently published a second consultation paper titled 'HVDC component of Transpower's proposed variation to the Transmission Pricing Methodology'. The HVDC component of the proposed variation set out that the TPM should be amended to allocate HVDC charges on a per-MWh basis, with an initial transition period.

2 The interconnection charge is one of the three main charges under the TPM, along with the connection and HVDC charges, and is paid by load.

3 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.

6 The consultation paper proposed that the Code should be amended to:

(a) use, in the calculation of the interconnection charge, N=100 for all four RCPD regions[4] *(the 'N=100 component')*

(b) exclude summer trading periods (ie from November to April inclusive) from the capacity measurement period (CMP) used to calculate RCPD *(the 'amended RCPD CMP component')*

(c) 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:

(i) the change would alter the incidence of most of the peaks in a 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

(the 'RCPD quantity adjustment provision component')

(d) provide for Transpower to adjust transmission charges when a reverse flow situation occurs *(the 'reverse flows component')*

7 The consultation questions are reproduced in Appendix A of this paper.

8 This paper summarises the submissions received in response to the consultation paper.

9 Comments on the HVDC component of Transpower's proposed variation (which was consulted on separately), and comments on how the Authority should conduct its review of the TPM, are not summarised in this paper. Submissions on those matters did not relate to the four components listed above.

10 The Authority's decision and reasons are described in a separate paper, available on the Authority's website at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/development/decisions-and-reasons-paper-published

Who made a submission

11 The Authority received twenty-three (23) submissions on the consultation, from the parties listed in Table 1.

12 This summary does not contain the full text of the submissions. However, the submissions have been published on the Authority's website at http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/consultations/#c15231

[4] 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.

Table 1 List of parties making submissions

Generators, retailers and their representatives	Consumers and consumer representatives	Distributors and distributor representatives	Other
Contact Energy *(Contact)* Genesis Energy *(Genesis)* – including a report by Castalia Independent Electricity Generators Association *(IEGA)* – including a report by Andrew Shelley Economic Consulting *(ASEC)* Meridian Energy *(Meridian)* Mighty River Power *(MRP)* Nova Energy *(Nova)* Pioneer Generation *(Pioneer)* Ringa Matau Trustpower	Carter Holt Harvey Pulp & Paper *(CHH)* Fonterra Co-operative Group (*Fonterra*) Major Electricity Users Group *(MEUG)* – including a report by the New Zealand Institute of Economic Research *(NZIER)* Norske Skog Tasman *(Norske Skog)* New Zealand Steel *(NZ Steel)* Pacific Aluminium *(NZAS)* Winstone Pulp International *(WPI)*	Aurora Energy *(Aurora)* Northpower Orion Powerco Unison Vector	Transpower

Comments on the N=100 component

There was mixed support for N=100 (Q1, Q4, Q9, Q10)

14 Fourteen submitters expressed support for the N=100 component (Contact, Genesis and Castalia, ASEC for IEGA, MRP, Northpower, Nova, Orion, Pioneer, Powerco, Ringa Matau, Transpower, Trustpower, Unison, Vector)[5].

15 Specific points raised in support included that the proposal:

(a) could reduce inefficient demand response[6]

(b) could result in an increased amount of demand response being made available for instantaneous reserve[7]

(c) would yield a net economic benefit[8]

(d) would be good for end consumers because their load would be controlled less often[9]

(e) would reduce the volatility of transmission charges in the USI and UNI[10]

(f) would align N between all four regions[11]

(g) would be consistent with actual load management and demand response practices[12]

(h) would not cause implementation or infrastructure costs[13]

(i) is unlikely to create significant costs[14]

(j) is widely supported by industry[15]

(k) would increase certainty in forecasting costs[16]

(l) would free up load management products from their current transmission pricing management requirements[17]

(m) is appropriate if Transpower does not expect major new investment to be required in the short to medium term[18]

5 See submissions from Contact (p3), Genesis (p1) and Castalia (p10), ASEC for IEGA (p1), MRP (p2), Northpower (p1), Nova (p3), Orion (p1), Pioneer (p1), Powerco (p1), Ringa Matau (p1-2), Transpower (p2), Trustpower (p12), Unison (p3), and Vector (p1).

6 Contact (p2), Genesis (p1) and Castalia (p2), and Powerco (p1).

7 Contact (p2).

8 Genesis (p1) and Castalia (p2), Pioneer (p1), and Trustpower (p1).

9 Northpower (p2).

10 Contact (p2) and Northpower (p6).

11 Contact (p3) and Orion (p1).

12 Orion (p1).

13 Contact (p2) and Transpower (p2).

14 Genesis (p1).

15 MRP (p2).

16 Contact (p2).

17 Contact (p2).

18 Vector (p1).

16 Four submitters expressed opposition to the N=100 component (Meridian, MEUG and NZIER, NZAS, WPI)[19].

17 Specific points raised in opposition included that:

(a) the Authority's cost benefit analysis (CBA) is based on simplifications and unsupported assumptions, and therefore it is uncertain whether there is a positive net benefit[20]. In particular:

(i) there is insufficient evidence to support assumptions on estimated costs, capacity and performance of existing and new embedded generation and load control[21]

(ii) there is insufficient evidence to support assumptions on elasticity of industrial load[22]

(b) the CBA overstates the benefit of the proposal because it

(c) does not take the outcomes of the Authority's review into account[23] there are plausible scenarios under which the net economic benefit of the proposal is negative[24]

(d) more CBA is needed[25]

(e) the identified benefit is small, relative to the amount of wealth transfers involved[26]

(f) the proposal might not result in a change in participant behaviour[27]

(g) the proposal, like the status quo, would give too strong a signal for load control at peak times[28]

(h) because the proposal would not be durable, it would not have the desired effect on investment[29]

(i) tthe proposal would not result in cost-reflective charges[30]

(j) the proposal will adversely affect some participants as it would decrease the UNI share of interconnection charges, while increasing all other region charges[31]

(k) there are better options for recovering interconnection costs[32]

(l) the problem should not be addressed until the Authority's own review has considered the issue[33]

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19 Meridian (p3), MEUG (p2) and NZIER (p22), NZAS (p5), and WPI (p1).

20 MEUG (p2) and NZIER (p9-12), Norske Skog (p1-2), and WPI (p1).

21 NZIER (p9).

22 NZIER (p9).

23 Meridian (p3, 6-7).

24 MEUG (p2).

25 Fonterra (p2).

26 MEUG (p2) and NZIER (p22).

27 NZIER (p12).

28 NZAS (p4).

29 Meridian (p1, 7).

30 NZAS (p5).

31 NZAS (p5).

32 Meridian (p5).

18 Four submitters did not support or oppose the N=100 component (Aurora, Norske Skog, CHH, and NZ Steel). Those submitters raised the following issues:

(a) although the proposal may reduce inefficient demand response, it may have unanticipated consequences. In particular, moving to N=100 may raise the interconnection rate, which would increase the incentive for demand response [34]

(b) the Authority's CBA:

(i) does not include evidence to support assumptions on estimated costs, capacity and performance of existing and new embedded generation, load control[35], and elasticity of industrial load[36]

(ii) is deterministic, and does not adequately address uncertainty via the use of sensitivity analysis[37]

(iii) overstates the economic cost of demand response[38]

(iv) does not consider the energy market benefits of demand response. In particular, load shedding at high peak load times can have a useful impact on consumer spot prices[39]

(c) the CBA overstates the benefit of the proposal because it:

(i) does not consider the energy market benefits of demand response[40]

(ii) does not consider transmission losses[41]

(d) the modelling horizon of the CBA is too short[42]

(e) the proposal might not result in a change in participant behaviour[43]

(f) the proposal will increase peak load[44], which may:

(i) stimulate a need for inefficient investment in peaking generation[45]

(ii) prevent the efficient decommissioning of existing assets[46]

(iii) inefficiently bring forward transmission investment[47]

(iv) cause overloading of assets[48]

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33 Meridian (p1), NZIER (p13).

34 Aurora (p3, p9).

35 Norske Skog (p2).

36 CHH (p2)

37 Norske Skog (p2).

38 CHH (p2)

39 CHH (p2).

40 NZ Steel (p2).

41 NZ Steel (p2).

42 NZ Steel (p1-2).

43 NZ Steel (p3). Aurora (p2 -3).

44 CHH (p1-2), Norske Skog (p5-6).

45 CHH (p1-2).

46 CHH (p1-2).

47 Norske Skog (p4-6), NZ Steel (p1), CHH p1.

48 Norske Skog (p4).

(g) the proposal is inconsistent with beneficiaries-pay[49]

(h) although N=12 is acceptable, the proposal may reduce some of the intensity of predicting and achieving the status quo[50]

19 No submitter expressed a view that moving to N=100 in the UNI or USI would materially *increase* the economic cost of demand response.

No submitters recommended drafting changes to the N=100 component (Q11)

20 Submitters did not suggest any drafting changes to the N=100 component..

21 Powerco indicated that it would have liked to see an option under which N was set to 100 for the UNI, but not for the USI.[51]

22 The proposed drafting also included changes to Appendix B of the TPM, which defines the four TPM regions. Transpower's submission provided a revised version of Appendix B.[52]

Some support for N=500, little support for other alternative options considered (Q1, Q5 – Q10)

23 The consultation paper assessed the proposal and the status quo against the following four alternative options:

(a) a RCPD option with N=500 in all four regions *(the N=500 option)*

(b) an option that is a per-MWh charge on gross load *(the per-MWh option)*

(c) an option that is a 50-50 mix of the status quo and a per-MWh charge on gross load *(the 50:50 option)*

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

24 Two submitters expressed a view that the N=500 option is likely to deliver more benefits than the proposal (Genesis and Castalia, and Unison)[53].

25 However, seven submitters opposed the N=500 option, for reasons including that:

(a) it would not result in significantly different outcomes from N=100[54]

(b) it could cause a greater amount of inefficient load management[55]

(c) peak demand would increase in all regions[56]

(d) it would have little or no moderating impact on the need for future transmission investment and would have a net welfare reducing effect as a result of lower energy consumption and/or inefficient investment in embedded generation[57]

49 Norske Skog (p4).

50 NZ Steel (p3).

51 Powerco (p1).

52 Transpower (p6).

53 Genesis (p2) and Castalia (p5), and Unison (p4).

54 CHH (p3), NZIER (p20), and NZAS (p4).

55 Northpower (p2).

56 Norske Skog (p5) and Nova (p2).

57 Powerco (p2).

26 Contact did not support or oppose the N = 500 alternative, but noted that as many systems are set to deal with 100 peaks, Contact expected that there would be additional cost implications relating to this alternative[58].

27 Meridian expressed in-principle support for charging based on gross load.[59] Otherwise, there was no support for the per-MWh or 50:50 options.

28 Fifteen submitters opposed the 50:50 and/or per-MWh options (Aurora, CHH, Contact, Fonterra, Genesis, ASEC for IEGA, Norske Skog, Northpower, Nova, NZ Steel, NZAS, NZIER, Trustpower, Unison, WPI)[60]. Reasons included that:

(a) MWh-based charges are likely to inhibit consumption of electricity by industrial consumers[61], which would have flow-on impacts including a reallocation of grid costs across remaining users[62]

(b) MWh-based charges could endanger the viability of some industrial consumers[63]

(c) MWh-based charges could change use of the network at peak times, potentially resulting in stranded assets[64]

(d) MWh-based charges could increase peak demand[65], potentially resulting in:

(i) increased transmission investment[66]

(ii) overloading of assets[67]

(e) MWh-based charges would not readily allow for an increased peak pricing signal if this became necessary in future[68]

(f) MWh-based charges would exacerbate the non-cost-reflectiveness of the transmission charging regime[69] or would be inconsistent with beneficiaries-pay[70]

(g) MWh-based charges would remove incentives for load management of grid-offtake loads as consumers with flat load profiles would be significantly disadvantaged and consumers with peaky load profiles would benefit[71]

(h) MWh-based charges would likely result in a shorter timeframe until the next grid upgrade was required, which would be inefficient[72]

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58 Contact (p2).

59 Meridian (p4).

60 Aurora (p5-6), CHH (p2-4), Contact (p3), Fonterra (p3), Genesis (p4), ASEC for IEGA (p1), Norske Skog (p5), Northpower (p2-3), Nova (p2-3), NZ Steel (p4), NZAS (p5), NZIER (p13-14), Trustpower (p8-9), Unison (p4), and WPI (p1).

61 CHH (p2), NZIER (p13), Norske Skog (p5), Trustpower (p8), and Unison (p4).

62 NZIER (p14)

63 CHH (p3), NZIER (p14), and NZAS (p5).

64 NZIER (p3).

65 Aurora (p9), CHH (p4), Norske Skog (p4), Northpower (p3), NZ Steel (p3), and NZIER (p9).

66 Norske Skog (p4), NZ Steel (p1), and NZIER (p9).

67 Norske Skog (p4).

68 Contact (p3), Trustpower (p9).

69 CHH (p1-2) and NZAS (p5).

70 Norske Skog (p1-2).

71 Northpower (p3).

72 Northpower (p3).

(i) MWh-based charges would be inefficient as Transpower would not have the flexibility to fine tune in the event of a step change in the market[73]

(j) MWh-based changes would likely breach the Ramsey pricing principle by directing more interconnection cost recovery to large industrial/commercial consumers who are likely to be more sensitive to variable electricity charges[74]

(k) there is insufficient evidence to justify the move to a MWh-based charge[75]

(l) the Authority's CBA overstates the costs of load control, which means that the benefit of a MWh-based charge is overstated[76]

(m) the Authority's CBA overstates the likely amount of new embedded generation in the absence of a per-MWh charge, which means that the benefit of a MWh-based charge is overstated[77]

(n) the Authority's CBA does not take enough account of the value of certainty to investors[78]

(o) the 50:50 option is unprincipled and would be unlikely to be durable[79]

(p) the 50:50 option would give mixed messages and unpredictable outcomes[80]

(q) these options are too novel[81]

(r) these options could have unintended consequences[82]

(s) these options are not well enough described in the paper[83]

(t) these options are less consistent with Code amendment principle 4 ('small-scale, trial and error') than the proposal[84]

(u) the economic benefits that accrue from shifting load away from peak demand periods would be muted and the effective cost of electricity in low summer demand periods would be excessively priced against the marginal cost of supply[85]

29 There was no support for the LRMC option.

30 Seven submitters opposed the LRMC option (Contact, Genesis, Norske Skog, NZ Steel, NZAS, NZIER, Trustpower)[86]. Reasons included that the LRMC option:

(a) would have the same disadvantages as the per-MWh option[87]

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73 Contact (p3).

74 Unison (p4-5).

75 ASEC for IEGA (p1), NZIER (p9), and Trustpower (p9).

76 CHH (p2), Norske Skog (p2), NZ Steel (p2), and NZIER (p10-11).

77 Norske Skog (p2) and Trustpower (p8-9).

78 Trustpower (p8-9).

79 NZIER (p21).

80 Northpower (p3) and NZIER (p21).

81 Fonterra (p3).

82 NZ Steel (p3), Trustpower (p9), and WPI (p1).

83 Trustpower (p8).

84 Trustpower (p9).

85 Nova (p2).

86 Contact (p3), Genesis (p5), Norske Skog (p5), NZ Steel (p4), NZAS (p5), NZIER (p22), and Trustpower (p8-9).

(b) would be complex and less transparent[88]

(c) is insufficiently described in the paper[89]

31 Trustpower commented that the CBA was inconclusive for all of the alternatives to the N=100 component[90].

32 NZIER suggested that the use of almost identical modelling for both the RCPD options and the MWh option is questionable, given that the MWh option is a structural change[91]. In light of this, NZIER submitted that the analysis of the effect of the MWh charge is missing some assumptions, including (for example) an estimate of the increased investment in the transmission network after the incentive to avoid use of the grid in peak periods is removed[92]

87 Norske Skog (p5), NZ Steel (p4), NZAS (p5), and NZIER (p22).

88 Contact (p3).

89 Trustpower (p8).

90 Trustpower (p8).

91 NZIER (p9).

92 NZIER (p9).

Comments on the amended RCPD CMP component and RCPD quantity adjustment provision component

There was mixed support for the amended RCPD CMP and RCPD quantity adjustment provision components (Q2, Q12, Q13, Q15, Q16, Q18)

33 Eleven submitters expressed support for the amended RCPD CMP component (Contact, Genesis and Castalia, MEUG, MRP, NZIER, Northpower, Nova, NZAS, Ringa Matau, Transpower, Trustpower)[93].

34 Specific points raised in support included that:

(a) it could reduce inefficiencies[94]

(b) it is appropriate to facilitate electricity demand at times when the marginal cost of generation is lowest[95]

(c) it is straightforward to implement and operate and would require no operational discretion from Transpower[96]

(d) it would effectively resolve the issue with NZAS shifting production to summer months without the need for the quantity adjustment provision[97]

(e) it would create certainty for all participants[98]

35 Seven submitters expressed opposition to the amended RCPD CMP component (Aurora, ASEC for IEGA, Meridian, Norske Skog, Orion, Powerco, Unison)[99].

36 Submitters raised the following disadvantages:

(a) the proposal could lead to increases in summer peak demand, which could inefficiently bring forward transmission investment[100]

(b) the proposal amounts to preferential treatment of NZAS, and it is more appropriate to resolve the problem through a prudent discount-like approach than by amending the TPM[101]

(c) the proposal is ad hoc, unprincipled, and/or a bespoke solution that may result in other participants lobbying for similar adjustments, or result in further adjustments to correct problems as circumstances arise[102]

(d) the proposed charge is not as broad-based as the status quo[103]

93 Contact (p2), Genesis (p2) and Castalia (p8), MEUG (p2), MRP (p1), NZIER (p22), Northpower (p3), Nova (p3), NZAS (p6), Ringa Matau (p1-2), Transpower (p2), and Trustpower (p10).

94 Genesis (p2), NZ Steel (p3), NZAS (p6), and Ringa Matau (p1-2).

95 Nova (p2).

96 Transpower (p2).

97 MRP (p9).

98 Northpower (p5)

99 Aurora (p4), ASEC for IEGA (p2), Meridian (p8), Norske Skog (p6), Orion (p2), Powerco (p2), and Unison (p4).

100 Norske Skog (p4), Castalia (p8), and Powerco (p2).

101 Aurora (p4-5).

102 ASEC for IEGA (p2), Meridian (p8), and Orion (p2).

103 Unison (p4)

(e) the proposal deals with a problem that may not exist after the Authority's review of the TPM[104]

(f) the proposal will adversely affect a significant number of participants[105]

(g) a better option for allocating interconnection charges exists that has not been considered[106]

37 CHH did not support or oppose the proposal. However, CHH said that it is crucial that RCPD signals make sure that there is no possibility of additional investment in the transmission network or peaking generation as a result of unconstrained peak demand[107].

38 Vector did not support or oppose the proposal. It noted that the proposed 20 business days' notification would have limited value for Vector as its network users' contribution to RCPD is primarily driven by consumer response to weather changes[108].

39 Eight submitters expressed support for the RCPD quantity adjustment provision component (Contact, Genesis and Castalia, MEUG, Nova, Powerco, Ringa Matau, Transpower)[109].

40 Specific points raised in support included:

(a) the same points that were raised in support of the amended RCPD CMP component

(b) that the RCPD quantity adjustment provision could be beneficial to industrial consumers during outages of their co-generation[110]

41 Four submitters expressed opposition to the RCPD quantity adjustment provision component (Aurora, Meridian, Northpower, Trustpower)[111].

42 Submitters raised the following disadvantages:

(a) the proposal would not provide NZAS with sufficient flexibility in making its consumption decisions[112]

(b) the proposal might lead some participants to apply load control at the wrong time, and hence create inefficient outcomes[113]

(c) the proposal would require Transpower to exercise administrative discretion[114]

(d) the proposal could have unintended consequences where multiple parties in the same region sought dispensations[115]

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[104] Meridian (p8).

[105] Aurora (p3-4).

[106] Aurora (p6).

[107] CHH (p2-3).

[108] Vector (p2).

[109] Contact (p4), Genesis (p2) and Castalia (p8), MEUG (p2), Nova (p1), Powerco (p2), Ringa Matau (p1-2), and Transpower (p2-3).

[110] Nova (p1).

[111] Aurora (p5), Meridian (p8), Northpower (p4), and Trustpower (p10)

[112] NZAS (p6).

[113] Northpower (p4).

[114] Meridian (p8).

[115] Meridian (p8) and Trustpower (p10).

(e) the proposal amounts to preferential treatment of NZAS and potentially other major directly connected industrial consumers[116]

(f) the proposal deals with a problem that may not exist after the Authority's review of the TPM[117]

(g) the proposal will adversely affect some other participants[118]

(h) a better option for allocating interconnection charges exists that has not been considered[119]

43 Of the submitters that expressed support for both of the components:

(a) Contact indicated a preference for the RCPD quantity adjustment provision, because it is more transparent[120]

(b) Genesis indicated a preference for the amended RCPD CMP, because it is simpler and less likely to have unintended consequences[121]Castalia noted advantages and disadvantages of both options, with the amended RCPD CMP being 'more conceptually robust but more burdensome'[122]

(c) MEUG, Ringa Matau and Transpower did not express a preference for one of the components over the other

(d) Nova recommended that both components should proceed[123]

44 NZAS indicated a preference for the amended RCPD CMP, and its preference that the RCPD quantity adjustment provision not be progressed on its own. This is because the RCPD quantity adjustment provision alone would not provide NZAS with sufficient flexibility in making its consumption decisions[124].

One submitter recommended a change to the amended RCPD CMP component (Q14)

45 While Meridian did not favour either the RCPD CMP component or the RCPD quantity adjustment component, Meridian, commented that, if the amended RCPD CMP component proceeded, it should only apply for a limited time period[125].

Some submitters commented on the drafting of the RCPD quantity adjustment provision component (Q17)

46 The proposed drafting refers to a comparison between 'the customer's offtake in the capacity measurement period' and 'the customer's previous offtake'. ASEC, Castalia and Meridian questioned the time period from which the customer's previous offtake should be drawn[126].

[116] Aurora (p4-5).

[117] Meridian (p8).

[118] Aurora (p4-5).

[119] Aurora (p6).

[120] Contact (p5).

[121] Genesis (p2).

[122] Castalia (p8)

[123] Nova (p1).

[124] NZAS (p6).

[125] Meridian (p9).

[126] ASEC for IEGA (p2), Castalia (p9) and Meridian (p8-9).

47 Castalia suggested that the first criterion (requiring a change in the incidence of 'most' peaks) could be removed[127]. MRP commented that if the RCPD quantity adjustment provision was adopted as an additional backstop measure, there should be a high threshold for its application to avoid Transpower being subject to excessive adjustment requests[128].

48 Northpower submitted that the requirements with regard to publication of a notice on Transpower's website[129] were inadequate, as they were not sufficiently detailed.

49 Transpower requested a change to provide for a three-month lead time, rather than the 20 business days proposed[130].

50 Transpower proposed new drafting for some of the proposed clauses to ensure that the onus is on the customer to demonstrate the case for its request to have its RCPD quantity adjusted[131].

51 Powerco made two proofreading comments[132].

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[127] Castalia (p8).

[128] MRP (p1).

[129] Northpower (p5).

[130] Transpower (p3, Appendix A).

[131] Transpower (p2-3, Appendix A).

[132] Powerco (p2-3).

Comments on the reverse flows component

The reverse flows component was broadly supported (Q3, Q19, Q20)

52 Fifteen submitters supported the proposal (Contact, Fonterra, Genesis, ASEC for IEGA, Meridian, MEUG, Norske Skog, Northpower, Nova, Pioneer, Powerco, Ringa Matau, Transpower, Trustpower and Vector)[133].

53 Four submitters commented that the reverse flows component was preferable to resolving reverse flows using ‘exceptional operating circumstances’ provisions (Genesis, Meridian, Powerco, Vector)[134].

54 No submitter opposed the proposal, or put forward reasons why it should not proceed.

Some submitters recommended drafting changes to the reverse flows component (Q21)

55 Northpower recommended that the drafting should set out *when* a customer should notify Transpower of reverse flows[135]. If the notification is after a reverse flow, the proposed drafting should set out a timeframe.

56 Powerco recommended that Transpower should be required to post a notice on its website when it adjusts quantities to minimise the effect of reverse flows[136]. The notice should specify how Transpower calculated the adjustment[137].

57 Transpower recommended that, in order to enable it to comply with its obligations under the amendment:

(a) the proposed clause should be limited to customers that have an agreement with the system operator under Schedule 8.3, Technical Code A, clause 6

(b) the definition of ‘GXP tie’ should be changed to reflect the drafting used in Schedule 8.3, Technical Code A, clause 6[138]

58 Contact recommended strengthening Transpower's obligations so that it is required to act when a reverse flow situation occurs.

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[133] Contact (p5), Fonterra (p3), Genesis (p7), ASEC for IEGA (p3), Meridian (p9), MEUG (p2), Northpower (p5), Nova (p4), Pioneer (p2), Powerco (p3), Ringa Matau (p1-2), Transpower (p3), Trustpower (p1), and Vector (p2).

[134] Genesis (p7), Meridian (p9), Powerco (p3), and Vector (p2).

[135] Northpower (p5-6).

[136] Powerco (p3).

[137] Powerco (p3).

[138] Transpower (p3, Appendix A).

Other comments

Problem definition and CBA – comments that are common to multiple components of Transpower's proposal

59 NZIER commented that Transpower and the Authority had not adequately defined or evidenced the problem definition[139].

60 Meridian commented that the CBA should have taken into account the potential outcomes of the Authority's review of the TPM[140].

61 MEUG emphasised the importance of robust CBA, commented that the CBA was not sufficiently robust, and expressed concern that the four components being consulted on would proceed despite inadequate CBA[141].

Roles and responsibilities of the Authority and Transpower

62 ASEC for IEGA commented that it had not been necessary for the Authority to carry out detailed analysis of Transpower's proposals, nor to consider alternatives[142]. ASEC submitted that the Authority's role in this situation is limited to ensuring that Transpower has followed the process in the Code, and approve the proposals.

63 Meridian commented that Transpower should not have carried out a substantive review of the TPM in parallel to the Authority's review of the TPM[143].

64 Norske Skog also commented on the undesirability of carrying out two reviews of the TPM in rapid succession[144].

65 Meridian commented that Transpower should only have proposed the reverse flows component, as the other three components are not of a technical nature[145].

66 MEUG suggested that only clear-cut problems with the TPM that have no downside for other parties not directly affected can be considered within the existing TPM Guidelines[146].

67 NZ Steel commented that Transpower's review is restricted to changes that are likely to be non-contentious[147].

68 NZIER queried how Transpower's proposals would fit with the Authority's review of the TPM[148].

69 Transpower commented that the TPM amendment process to date had generally been effective but that there was scope to clarify the interpretation of clauses 12.85 and 12.91 of the Code, and sought a post project review[149].

139 NZIER (p1).
140 Meridian (p1-2, 6).
141 MEUG (p2).
142 ASEC for IEGA (p3).
143 Meridian (p1).
144 Norske Skog (p1).
145 Meridian (p1).
146 MEUG (p3).
147 NZ Steel (p1).
148 NZIER (p2).

70 Trustpower expressed support for Transpower undertaking periodic reviews of the TPM[150].

71 Trustpower commented that the Authority should only have assessed Transpower's compliance with the process and content requirements in Part 12, and should not have considered or proposed other alternatives[151].

72 Trustpower commented that it was not clear whether the Authority could approve the amended RCPD CMP component or the RCPD quantity adjustment provision component, as those components had not been consulted on by Transpower[152].

73 WPI commented that some of the proposals were a major departure from the current TPM. Those proposals should be considered as part of the Authority's review of the TPM[153].

Other matters

74 Aurora recommended that interconnection charges should be allocated according to the average anytime demand (N = 100) presented by individual GXPs[154].

75 MEUG disagreed with Transpower's view that the five components originally proposed by Transpower had previously been broadly supported by the industry[155].

76 MEUG complained about Transpower's ability to charge for transmission services even when no party receives any benefit from them[156].

77 NZIER emphasised[157]:

(a) the competition and efficiency benefits of distributed generation and co-generation

(b) the importance of declining demand, supply-side disruption and climate change

(c) the potential for disruptive technologies and market developments

(d) the value, but practical difficulty, of beneficiaries-pay charging approaches

78 NZAS complained about the level of transmission charges that it is required to pay[158].

79 Orion commented that any reduction in demand response in the USI may bring forward transmission investment, and expressed concern about the Authority's other initiatives that may impact demand response[159].

80 Pioneer commented that the Authority should consult with stakeholders if it decided to progress any of the alternative options discussed in the consultation paper[160].

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149 Transpower (p1-2).

150 Trustpower (p1) .

151 Trustpower (p3).

152 Trustpower (p4).

153 WPI (p1).

154 Aurora (p6).

155 MEUG (p1).

156 MEUG (p3).

157 NZIER (p15-16).

158 NZAS (p1).

159 Orion (p1-2).

160 Pioneer (p1-2).

81 Ringa Matau and Vector supported gradual change to the TPM[161].

82 Transpower noted that the Authority had mistakenly included a change to clause 16 of the TPM in Appendix B of the consultation paper[162].

83 Unison commented on how RCPD pricing signals are passed through to end-consumers and affect network management decisions[163].

84 Unison recommended that the transmission pricing methodology should include some fixed charges on load parties[164].

161 Ringa Matau (p1).

162 Transpower (p3, Appendix A).

163 Unison (p2).

164 Unison (p3).

Appendix A Consultation questions

#	Question
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.

#	Question
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?