Summary of submissions

Transmission Pricing Methodology: issues and proposal consultation paper

28 May 2013

787484-2

Executive summary

The Electricity Authority (Authority) is reviewing the transmission pricing methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover costs of providing transmission services.

The Authority released for consultation the *Transmission Pricing Methodology: issues and proposal* consultation paper (consultation paper) on 10 October 2012. The consultation paper outlined the Authority's assessment of the current TPM, proposed a revised TPM, and explored alternative options.

Submissions were received from 54 parties. Submissions were received from a wide range of parties including Transpower, distributors, retailers, generators, a wide range of consumers and consumer groups, subsidiaries and parent companies, and individuals.

This paper summarises submitter views by theme with the themes correlating to questions from the consultation paper. Note that cross-submissions are summarised in a separate document.

What the Authority wanted to know

The Authority sought submitter views on the following:

- context to transmission pricing - material change in circumstances: the Authority determined that material changes in circumstances warrant a review of the TPM, as required under clause 12.86 of the Code
- context to transmission pricing – process for the TPM review
- decision-making about the TPM: the Authority used an economic framework to identify and assess options for the TPM
- problem definition: the Authority identified several aspects of the current TPM that it considers are not consistent with promoting efficiency and promoting the long-term benefits of consumers
- proposed amendments to the TPM: the Authority proposed amendments to the current TPM have been divided into the following categories:
    - loss and constraints excess (LCE)
    - connection charges
    - reactive support (static and dynamic)
    - beneficiaries-pay, the Scheduling Price and Dispatch (SPD) model (this category includes a number of sub categories)
    - residual charges (this category includes a number of subcategories)
    - prudential discount policy (PDP)
    - the Authority's cost-benefit analysis calculating the net benefits of the proposal
    - assessment of the proposal against the Authority's statutory objective

– impacts on distributed generation (feedback on the impacts of the proposal on distributed generation was not specifically requested by the Authority. Submitter comments relating to distributed generation have been included as a separate category due to the high level of submitter interest)

– evaluation of alternatives: the Authority considered various alternative methods for establishing charges to recover transmission costs, including market and market-like approaches, exacerbators-pay approaches, beneficiaries-pay approaches and other alternative approaches

– proposed guidelines: the Authority prepared draft guidelines to be followed by Transpower in preparing a its TPM

– draft process for development and approval of the TPM: the Authority prepared a draft process for development and approval of the TPM.

The main themes from submissions

The following provides a summary of the main themes from submissions. Summaries of both majority and minority views are included.

Context: Material change in circumstances

- 13 out of 19 submitters considered that there had not been a material change in circumstances since 2008, and the Authority's TPM review was unfounded. Notwithstanding this position, a number of submitters agreed that a material change in circumstances had occurred, particularly with reference to HVDC charges. For example, 12 submitters appeared to support an amendment to the HVDC component of TPM charges.

Context: Process

- Overwhelmingly, the consensus view in submissions was that, given the magnitude of changes being proposed, the Authority needs to undertake further consultations.
- In addition, there was a strong desire to see the Authority further engage with industry, particularly through the use of an industry working or advisory group to inform any changes to the current TPM.

Decision-making about the TPM

- Two key themes emerged from the eight submitter comments on the decision making framework:
  - there were submitter concerns that the Authority's economic and decision making framework could not be practicably applied to transmission pricing
  - some submitters suggested that the Authority misrepresented the level of industry support for the framework.

Problem definition

- The dominant theme that emerged from relevant submitter comments was the view that the Authority failed to adequately prove that a problem exists with the current TPM, and the view that the Authority's views lacked a robust supporting analysis.
- More specifically, submitters commented that there was a lack of supporting analysis applied to both the Authority's problem definition at a high level and also to specific sub-components of the Authority's problem definition.
- While ten of 13 submitters considered there was inefficient operation of South Island generation due to the current HVDC charges, five submitters took the view that such inefficiencies are not likely to have a material cost. Only two out of 11 submitters considered that there were material differences between interconnection charges and private benefits arising from interconnection assets. Thus it might be concluded that the Authority has not sufficiently defined the problem in relation to interconnection charges.

Proposal: LCE

- A majority of parties commenting on the LCE proposal supported the concept of the proposal although a number of submitters did not think that LCE should be offset against individual assets but rather it should be offset against Transpower's overall annual revenue requirement. It was considered that this modification would cause a reduction of residual charges rather than a reduction to SPD charges, and lead to reduced volatility of charges overall.
- Some submitters such as Smart Power and NZX agreed with the Authority's proposal considering that it would create a fairer process, while some submitters were concerned that the proposal would mute nodal price signals.
- Other submitters considered that the proposal would increase the volatility of TPM charges and result in greater complexity in the price setting process while NZX considered that the proposal would open the possibility of direct payments to participants from the clearing manager.

Proposal: connection

- Many submitters did not comment on the Authority's proposal in relation to connection charges. Of those that commented, around half of the submitters supported or broadly supported the Authority's connection charge proposals. Powerco provided some technical detail in relation to the Authority's proposal, while Transpower considered that changes would cause more problems than the minor issues they sought to address.

Proposal: static reactive support

- Many submitters supported the Authority's static reactive support proposal. Genesis suggested that the Authority ensure distributors replicate the charge in their network prices to ensure the efficiency of the charge.

Proposal: dynamic reactive support

- Many submitters raised issues with the Authority's dynamic reactive support proposal and many submitters expressed preference for the status quo position. Transpower advised that SPD would not reveal the impact of reactive power devices.

Proposal: beneficiaries-pay approach

- While there appeared to be extensive support for the concept of a beneficiaries-pay approach, many submitters considered there were practicality issues in moving to beneficiaries-pay and a number of other submitters did not support the concept of beneficiaries-pay. Some submitters preferred the status quo approach which was considered by Unison to contain elements of beneficiaries-pay. DEUN considered that the Authority should give consideration to an exacerbators-pay approach.
- Many submitters requested that the Authority give further consideration to the proposal and provide greater details on how the Authority will address the various submitter concerns. Orion suggested the Authority consider the beneficiaries-pay approach in a longer term context.

Proposal: SPD model

- The majority of submitters had significant issues with many parts of the SPD model while seven submitters indicated qualified support.[1] The main issues identified were that the model would create volatile, uncertain charges that would increase the risk premium associated with electricity investments, and thus cause price increases and create barriers to market entry.
- A number of submitters suggested modifications to the model which they considered would reduce volatility and increase the certainty of the charge.
- There were divided views over whether the HVDC should be rolled into the interconnection charge, with large South Island generators generally preferring changes to the HVDC charge while the majority of consumers preferred status quo HVDC charges.
- The following provides a brief breakdown of submitters' comments on particular components of the proposed SPD model.
  - **Half-hourly calculation of benefits**: Many submitters considered the proposed half-hourly calculation of benefits does not correctly reflect long- term benefits that characterise long term investments.
  - **Half-hourly cap**: Many submitters considered that the proposed half-hourly cap reduces the cost recovery potential of SPD. Some submitters thought there should be no cap while other submitters preferred a longer term cap (either weekly or monthly).

[1] Partial support for the SPD method was from MEUG, NZX, Pacific Aluminium, Meridian, Smart Power, Business NZ, and Nova

- **Monthly ex-post charges**: Many submitters considered the proposed monthly ex post charge allocation would increase the uncertainty of TPM charges.
- **Inclusion of generators in SPD**: Many submitters considered that the inclusion of generators in SPD would result in generators, particularly SI generators, passing costs through to consumers.
- **HVDC charge allocation**: Submitters were divided over changes to HVDC charges. Those supporting change advised that current charges were inefficient, while those supporting status quo charges submitted that SI generators were largely the beneficiaries of HVDC and that the costs of HVDC were sunk and should not be reallocated.
- **Assets included in SPD**: Many submitters felt the proposed threshold is too low for inclusion of current and future assets in the SPD model and submitted that the model could be improved by increasing the threshold and including only a small number of assets in SPD. Some parties suggested only future assets be included in SPD.
- **Reliability**: Some submitters considered that reliability is inadequately considered by the SPD model.
- **Estimation of benefits and dis-benefits**: Some submitters considered that the SPD model does not accurately calculate benefits and does not consider dis-benefits.
- **Unserved energy variable** : Submitters were divided on an appropriate value for unserved energy with some submitters preferring a higher value to reduce market distortions while those preferring a lower value, mainly consumers, contended that $3,000/MWh was based on a short term view of a counterfactual.
- **Counterfactual**: Some submitters considered the counterfactual should be more clearly defined and some submitters considered the counterfactual should reflect a long term perspective.

Proposal: detrimental impacts of SPD

- Submitters discussed what they considered to be the various detrimental impacts of the proposed SPD model. Some of these views were that the charges would:
  - cause volatile, complex and uncertain charges
  - increase prudential requirements and thus create barriers to entry
  - increase the risk premium associated with electricity investments
  - lessen incentives for participants to respond to peaks
  - create gaming opportunities and cause generators to manipulate their wholesale market offers
  - increase the cost of electricity.

Proposal: alternative beneficiaries-pay charging options

- Many submitters suggested alternative beneficiaries-pay options. Some of these alternatives included variations to the SPD model while others were non-SPD alternatives.
- Many of the SPD alternatives were likely attempting to reduce volatility and increase the certainty of transmission charges (i.e. ex-ante charges rather than ex-post charges).
- Some submitters suggested that beneficiaries-pay should be confined to future investments only. One submitter suggested that a one-off estimation of beneficiaries should be made at the time an investment is approved.
- Some submitters preferred the status quo approach while some preferred the status quo approach with the HVDC costs rolled into the interconnection charge.
- Some submitters recommended a transition period for incorporation of HVDC into interconnection charges to reduce the impact of wealth transfers.

Proposal: residual charges

- Submitter comments on the Authority's residual charge proposal are separated into subcategories below:
  - **Proportion of allocation between RCPI and RCPD**: Many submitters opposed the concept of RCPI charges for the residual charge. Some submitters, such as Unison, were concerned that generators would be incentivised to avoid generating at times of peak demand (to avoid incurring residual charges), at times when generation was most required. Other submitters were concerned that generators would pass the cost on and cause higher consumer prices. Genesis considered that it would discourage generation investment and accelerate retirement of existing peaking generation.
  - Some submitters opposed the proposed residual 50:50 allocation to generation and load on the grounds that the rationale was arbitrary, did not conform to international practise[2], and did not represent benefits. TrustPower suggested that SPD could be used to provide a more accurate split between generation and load.
  - Some submitters preferred MWh based charges over an RCPI charge on the basis that a MWh charge would be less distortionary.
  - **Opt-out**: There was little support for the opt-out proposal, except qualified support from Powerco and Vector and with PwC supporting the opt-out proposal only if the SPD model went ahead. One of the most common issues identified was that the opt-out clause may reduce or eliminate distributor incentives to engage in load control.
  - New contractual requirements and system issues were other common issues communicated through submissions. Powerco suggested the

[2] Meridian submission, p. 45

Authority further develop the legal arrangements that would apply while Clearwater suggested the opt-out facility represented the biggest risk to its systems and network security.

- **Residual charge complementary to beneficiaries-pay**: Transpower and ENA submitted that the Authority needed to be clear about the objective of the residual charge if applied in conjunction with the SPD charge. Transpower and ENA considered that there was confusion as to whether the Authority intended the residual to incorporate a pricing signal or whether the charge should be non-distortionary.
- A number of submitters made suggestions for the improvement of the residual charge to make it more complementary to a beneficiaries-pay approach. Genesis suggested the Authority investigate a large range of options and combinations.
- **Minimising distortion**: Submitters such as Powerco considered the current RCPD charge went some way towards signalling LRMC cost while also minimising distortion. Many submitters considered the RCPI charge distortionary and some submitters contended that there was a lack of clarity about how RCPD and RCPI will be applied. Further consideration was requested from MEUG, Contact, Waipa, and Genesis.
- **Full recovery of transmission costs**: Five submitters agreed that the residual would enable full cost recovery while one submitter considered over recovery was possible, and another submitter considered it was not realistic to expect full cost recovery for uneconomic investments and that some assets should be written-down.
- **Efficient avoidance of peak regional use**: Orion questioned whether encouraging efficient usage contradicted the objective of minimising distortion and submitted that (the RCPI part of) the proposal would reduce investment in peak avoidance. Transpower suggested that a charge to generators would increase unintended price signalling.
- There were competing views on the prospect of reviewing existing RCPD regions.

Proposal: prudent discount policy (PDP)

- 26 submitters commented on the Authority's PDP proposal. Most comments were in support of the changes, while some parties considered that changes to the current regime were unnecessary.

Proposal: cost-benefit analysis

- The majority of submitters did not support the Authority's approach to the CBA while one submitter considered that the proposed TPM was more efficient than the status-quo but presented a preferred alternative TPM.
- In addition to commenting on the assessment of the costs and benefits used in the CBA, many of the submitters broadened their comments to

cover other CBA framework issues including the baseline forecast; and impacts on submitters including embedded generators.

- The main theme of the dissenting submissions was that the CBA was unorthodox and not sufficiently robust to support the case for the proposed TPM, particularly given the extent and importance of the proposed changes. A common view was that the scope of the analysis was not sufficient to determine whether or not the proposed TPM was indeed the best policy option.
- Many submitters considered that the Authority's approach to the CBA was too high-level and subjective, making it inappropriate for the TPM proposal.
- There was a common view that the benefits of the TPM reform were overstated and that the costs were underestimated. Many submitters anticipated that the proposed TPM would produce detrimental unintended consequences and argued that these needed to be factored into the CBA.
- A number of submitters commented on the detrimental impact of potential wealth transfers arising from the proposed TPM. Further, a number of submitters raised concerns about the uncertain impacts of the proposed TPM on embedded generators.

Proposal: assessment against the Authority's objective

- Many submitters considered the proposal did not adhere to the Authority's objective. The most common concern was that the proposal would result in higher electricity costs and therefore could not be in the long-term benefit of consumers.
- PwC submitted that the significant wealth transfers, that were inherent in the proposal, would undermine confidence and negatively impact dynamic efficiency and thus detrimentally impact the long-term benefit of consumers.

Proposal: impacts on distributed generation

- Many submitters had strong views on the negative impact of the Authority's proposal on distributed generation while other parties requested that the Authority address, more specifically, uncertainties around the impacts of the proposed TPM on distributed generation. Particular issues that distributed generators had were: that the proposal goes against recent Government policy to incentivise distributed generation; that allocation of SPD and residual charges to generators would result in increased generator costs and involve direct billing of charges; that a reduction of RCPD will lead to reduced Avoidable Costs of Transmission (ACOT); and that increased volatility and uncertainty around the proposed TPM charges would disadvantage smaller generators.
- Some submitters had concerns about the Authority combining generation at each GXP when applying the 10MW threshold for inclusion in the SPD model. Meridian recommended that distributed generators be included in SPD only if they are greater than 10 MW. CHH suggested the Authority should use net load, rather than gross load, at location points, because it

was not equitable to charge generators for grid injections in net off-take situations.

- Pioneer advised that it had concerns about system operator discretion to have its distributed generation dispatched. According to Pioneer, this could result in Pioneer incurring SPD charges which it had no control over.

Evaluation of alternative means of achieving the objectives

- A dominant theme that emerged from submissions was a desire to see the Authority undertake further analysis and consider alternatives.
- Connected with the desire for the Authority to undertake further analysis and consideration of alternatives, was the view that the analysis of the alternatives also needed to include additional detail on the impacts of the alternatives.
- In terms of the different classes of alternatives:
  - there was generally a lack of support for the use of market-based or market-like approaches
  - there was some support for the Authority's acceptance of the TPAG's evaluation of alternative exacerbators-pay approaches
  - there was mixed support for alternative beneficiaries-pay approaches. Some of the approaches suggested included zonal postage stamp, flow tracing, expansion of the deep sunk cost allocation, and the forecast model approach.

Proposed guidelines for Transpower

- While some parties considered the draft guidelines were adequate, many parties considered that the draft guidelines did not provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option. Submitters suggested more detail, in order to reduce the operational discretion given to Transpower in developing a revised TPM. MEUG and NZ Steel felt that left with discretion, Transpower would not give appropriate consideration to consumers' interests.
- Transpower and others suggested that since the guidelines draw heavily on the Authority's proposed TPM changes, the TPM changes should be addressed in advance of consideration of the content of the guidelines. Orion submitted that there were technical issues that might create difficulties in implementing a revised TPM and suggested these issues are explored before detailed design commences.
- Some of the submitters did not support the guidelines on the basis of their opposition to the Authority's proposal in general, or issues with particular parts of the Authority's proposed TPM.
- Vector considered that the Authority exceeded its mandate and went beyond the development of developing mere guidelines, thus encroaching on Transpower's mandate to develop a TPM. Vector recommended that the Authority restrict itself to developing guidelines and principles.

Draft process for development and approval of TPM

- **Development:** Around half of the submitters agreed in general with the Authority's draft process for development. Common reasons in submissions for not supporting the Authority's process were that TPM design should be completed before consideration of the process, and that Transpower's operational discretion needed to be reduced.
- Powerco suggested that reviews of the Benchmark Agreement and Connection Code were required and should be included within the process.
- Smart Power requested further information on what the Authority's consultation on the process would cover.
- Parties were highly supportive of the Authority's position not to require Transpower to propose how costs that are related to revenue not subject to regulatory review by the Authority or the Commerce Commission, would be determined and allocated. Orion pointed out that LCE is not currently regulatory revenue for Transpower.
- Many parties considered that it was overly ambitious to have the amended TPM in place for the April 2015 pricing year. Many submitters argued that the timeframe could not realistically be established until a range of matters were addressed and the full implications of the proposal are revealed through detailed design.
- CHH and MEUG suggested the Authority take guidance on timeframes from Transpower. Transpower suggested 1 April 2017 was a practical implementation date assuming final pricing guidelines were available by June 2013.
- **Approval:** The Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower was widely supported by most submitters. However Transpower considered an earlier indication of when industry consultation is likely and the likely duration of the consultation would be beneficial.
- Powerco suggested that, given complexity, a consultation period of more than six weeks would be necessary.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
CBA	Cost Benefit Analysis
CIC	Customer Investment Contract
DG	Distributed Generation
FTR	Financial Transmission Rights
HAMI	Historical Anytime Maximum Demand
GWh	Gigawatt hours
HVAC	High Voltage Alternative Current
HVDC	High Voltage Direct Current
Kvar	Kilo-volt ampere reactive
LCE	Loss and Constraints Excess
LNI	Lower North Island
LSI	Lower South Island
MAR	Maximum Allowable Revenue
Minister	Minister of Energy and Resources
MW	Megawatt
NAaN	North Auckland and Northland project
NPV	Net Present Value
NRS	Network Reactive Support
PDP	Prudential Discount Policy
RCPD	Regional Coincident Peak Demand
RCPI	Regional Coincident Peak Injection
SPD	Scheduling Pricing and Dispatch
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
vSPD	vectorised Scheduling, Pricing and Dispatch

Glossary of submitters

Submitter	Abbreviation used in this paper	Submitter	Abbreviation used in this paper
Alinta Energy	Alinta	New Zealand Geothermal Association	NZGA
Auckland Chamber of Commerce	ACC	New Zealand Steel	NZ Steel
Auckland Council	Auckland Council	New Zealand Wind Energy Association	NZWEA
Auckland District Health Board	ADHB	Norske Skog Tasman	Norske Skog
Auckland Energy Consumer Trust	AECT	Northpower	Northpower
Auckland International Airport Limited	Auckland Airport	Nova Energy	Nova
Buller Electricity	Buller Electricity	NZX Limited	NZX
BusinessNZ	Business NZ	Orion New Zealand Limited	Orion
Carter Holt Harvey Pulp Paper Limited	CHH	Pacific Aluminium	Pacific Aluminium
Clearwater Hydro	Clearwater Hydro	Philip Wong Too	Philip Wong Too
Contact Energy Limited	Contact	Pioneer Generation	Pioneer
Domestic Energy Users' Network	DEUN	Powerco Limited	Powerco
Electric Power Optimization Centre	EPOC	PricewaterhouseCoopers	PwC
Electricity Networks Association	ENA	Pulse Utilities	Pulse
Employers & Manufactures Association	EMA	Ringa Matau Limited	Ringa Matau Limited
Energy for Industry	Energy for Industry	Simply Energy	Simply Energy
Energy Link	Energy Link	Smart Power	Smart Power
Energy Market Services	EMS	Taharoa C Block	Taharoa C

Submitter	Abbreviation used in this paper	Submitter	Abbreviation used in this paper
Energy3	Energy3	Tauropaki	Tauropaki
Fonterra	Fonterra	Transpower	Transpower
Genesis Power Limited	Genesis	TrustPower Limited	TrustPower
Kiwi Rail Holdings Limited	Kiwi Rail	Unison Networks Limited	Unison
MainPower	MainPower	Vector Limited	Vector
Major Electricity Users' Group	MEUG	Ventus Energy NZ Limited	Ventus
Meridian Energy Limited	Meridian	Waipa Networks Limited	Waipa
Mighty River Power	MRP	Wellington Electricity Lines Limited	WEL
New Zealand Council for Infrastructure Development	NZCID	Winstone Pulp International Limited	WPI

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1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 The Authority is reviewing the TPM, which specifies the method for Transpower to recover costs of providing transmission services.

1.1.2 The Authority released the consultation paper inviting interested parties to make submissions by 30 November 2012 and to make cross-submissions by 21 December 2012. The Authority announced an extension of the consultation period on 27 November 2012, asking parties to make submissions by 1 March 2013 and to make cross-submissions by 28 March 2013.

1.2 Purpose of this paper

1.2.1 This paper provides a summary of the submissions received on the consultation paper.

1.2.2 The submissions received covered a range of issues. This paper does not provide an exhaustive listing, but instead seeks to identify the major issues and themes reflected in the submissions. It is a summary of the submissions only, and the inclusion or exclusion of any submission, or any part thereof, does not mean any judgment has been made on the submissions by the Authority.

1.2.3 This paper summarises submitter views by theme, with the themes correlating to topics from the consultation paper. Each theme contains a summary, and these summaries are collated in the Executive Summary section of this paper.

1.2.4 At the beginning of each 'feedback' section, the Authority provides its assessment of the number of submitters that support or partially support, or do not support, the Authority's findings or parts of its proposal. It should be noted that these are estimates only as it is occasionally difficult to gauge a submitter's position based on their comments, particularly where both positive and negative points are provided in relation to a topic. The Authority has taken the view that, where a submitter requests more information and appears broadly neutral, this is taken as partial support. i.e. the submitter appears to be considering the proposition, and pending further information it may take a favourable view, or may take a favourable view if parts of the proposal were amended in some way(s).

1.2.5 Note also that at the beginning of each 'feedback' section, where the Authority provides its assessment of the number of submitters that support or partially support, or do not support the Authority's views, the numbers of submitters do not normally add up to the total number of submitters (54). Where the Authority considers that submitters did not specifically comment on a topic, these submitters have not been included in the assessment. For example, if the paper states that 10 submitters agreed with the Authority's proposal and 10 did not agree, this implies that 34 submitters did not comment.

1.2.6 Furthermore, given that a number of submitters did not specifically answer questions in the format requested by the Authority, and given the high number of submission pages (1304 pages), the Authority was occasionally required to make a judgement as to whether a submitter commented specifically on a topic or not.

1.2.7 Note that cross-submissions are summarised in a separate document.

1.2.8 Note that the opinions provided within this document represent submitters' views and are not the views of the Authority.

2. Overview of submitters

2.1.1 Submissions were received from 54 parties, as detailed in Table 1 below.

2.1.2 Submissions were received from a wide range of parties representing transmission, distributors, retailers, generators, a wide range of consumers and consumer groups, consultancy firms either individually or on behalf of parties, subsidiaries and parent companies, and individuals. Note the list below.

Table 1: List of sectors that submitters were considered to predominantly represent

Retailers and Retailer/Generators	Distributors	Consumers	Generators	Other
Meridian	PwC*	Auckland Council	Ventus	Transpower
Smart Power	ENA*	Kiwi Rail	Clearwater Hydro	Philip Wong Too
Genesis	Northpower	CHH	Ringa Matau Limited	ACC*
MRP	Powerco	DEUN*	Energy3	Business NZ*
Simply Energy	WEL	ADHB	Pioneer	AECT
Pulse	Buller Electricity	Auckland Airport	NZGA*	Energy for Industry
TrustPower	MainPower	Pacific Aluminium	NZWEA*	Energy Link
Nova	Unison	WPI	Taharoa C	NZCID*
Contact	Orion	Fonterra	Alinta	EPOC
	Waipa	Norske Skog	Tuaropaki	NZX
	Vector	NZ Steel		EMS
		MEUG*		EMA (Northern)*

* Submitter represents a group of parties

3. Context: Material change in circumstances (Question 1)

3.1 Overview: Material change in circumstances

3.1.1 The Authority detailed its view that material changes in circumstances warrant a review of the TPM, under clause 12.86 of the Code. Since 2008:

(a) there has been more than $2b worth of transmission investment approved by relevant regulatory bodies

(b) there have been significant changes to the regulatory framework governing grid investments, including a transfer of approval function from the Electricity Commission to the Commerce Commission

(c) technological advances and reduced computational costs permit more sophisticated means of allocating transmission costs.[3]

3.2 What the Authority asked

3.2.1 The Authority sought submitter views about the materiality of changes in circumstances since the current TPM came into force in 2008 **(Question 1)**.

3.3 Feedback: Material change in circumstances (Question 1)

3.3.1 13 out of 19 submitters considered that there has not been a material change in circumstances since 2008, and the Authority's review is unfounded. However, elsewhere in submissions a number of the submitters that did not consider that there had been a material change in circumstances agreed that the current TPM could be amended, particularly with reference to HVDC charges. For example, 13 submitters[4] appeared to support amendments to the HVDC component of TPM charges.

3.3.2 In respect of the Authority's view that there has been a material change in the level of transmission investments since 2008, submitters responded that this does not constitute a material change because:

(a) the $2 billion in transmission investment are sunk costs and cannot be undone, regardless of their efficiency. As put by Orion *"many of the key transmission investments for the next 10 to 20 years have*

[3] Consultation Paper, p. 34. See paragraphs 2.3.9 – 2.3.12.

[4] NZWEA, Genesis, MRP, NZX, Transpower, Powerco, Buller, Meridian, MainPower, Pulse Utilities, Nova, Contact, TrustPower

already been made, and the associated decisions, good or bad, cannot be undone"[5]

(b) the investments since 2008 were done under, and envisaged by, the current TPM. Powerco, for example, commented that *"the major investments referred to in paragraph 2.39(a) of the discussion document were already well in train when the current TPM was approved by the former Electricity Commission"*[6]

(c) there will be low or minimal transmission investments going forward, so the ability of the proposed TPM to influence investments, and the potential benefits from changing the TPM, will be minimal. As Transpower noted in their submission *"we expect to make very few large investments in coming years, so the potential benefits from deferring grid investments are limited at this time. In other words, there is a mismatch between the material change cited, and the pricing change that is proposed."*[7]

3.3.3 On the issue of changing regulatory governance, submitters arguing against the materiality of changed circumstances, contended that the:

(a) change of regulatory oversight from the Electricity Commission to the Commerce Commission has largely just been a transfer of function and decision making frameworks. TrustPower, for example, commented that *…*there is no link between the change in governance arrangements and the need for the proposed changes[8]

(b) TPM should not be changed so that the Commerce Commission can settle into its role[9] and *"…the fact that the Commerce Commission has only recently assumed responsibility for grid approvals is in our view a significant reason* <u>*not*</u> *to seek to materially change the TPM. Doing so without careful consideration creates the risk of jurisdictional overlap and confusion with the Commerce Commission's price-quality control regulation of transmission services"*[10]

(c) way in which grid investments are approved has not materially changed,[11] and that is for the Commerce Commission's Grid Investment Test to determine the efficiency of grid investments, and not the Authority's TPM.[12]

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5 Orion submission, p. 14

6 Powerco submission, p. 6

7 Transpower submission, Appendix A, p. 1

8 TrustPower, submission, Appendix A, p. 1

9 Ringa Matau submission, p. 1

10 MRP submission, p. 24

11 Powerco submission, p. 6

12 MRP submission, p. 24

3.3.4 In regards to whether or not a change in technology has been a material change in circumstance:

(a) The general view was that whilst there had been improvements in technology and a reduction in computational costs, this was not a reason in and of itself to justify changing the TPM. Orion expressed the position that technology changes are only a material change if technology was the reason other transmission pricing approaches hadn't been applied in the past[13]

(b) In addition, submitters also took the view that that complexity shouldn't be introduced just because the technology can now handle more sophisticated pricing methods. As put by MRP *"having the computation ability to undertake more complexity should not be seen as a justification in and of itself."*[14]

3.3.5 There was considerably less comment from the six submitters who believe there has been a material change in circumstances since 2008 and that the Authority's review of TPM is warranted. [15] These submitters generally agreed with the reasons provided by the Authority in its consultation paper.

3.3.6 However, in addition to the Authority's reasons, submitters who expressed support of the Authority's review suggested that the TPM needs to be reviewed because:

(a) the current TPM has not been structured to improve the dynamic efficiency of investments since 2004, and therefore the current TPM cannot be to the long-term benefit of consumers[16]

(b) Transmission Pricing Advisory Group (TPAG) and Authority analysis that reveals the beneficiaries of the HVDC to be widespread is another material change in circumstances since 2008. This analysis has shown that the HVDC charge is inefficient and unsustainable, the Authority has a statutory duty to act, and a review of the TPM is therefore justified[17]

(c) the TPM needs to consider the impact of flattening demand for energy and declining use of grid assets.[18]

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13 Orion submission, p. 14

14 MRP submission, p. 24

15 See, for example, submissions from CHH, the Major Electricity Users Group, Meridian Energy, NZ SteelNZ Steel, NZX and Pacific Aluminium.

16 Pacific Aluminium submission, p. 12

17 Meridian submission, p. 67

18 See submissions from CHH, the DEUN and NZ Steel.

3.3.7 Some of the submissions also queried the urgency of needing to review TPM, arguing that whilst it is important and warranted, the TPM should be considered in the context of broader energy sector reforms and the on-going operational environment. For example:

(a) DEUN suggested that efficient transmission pricing should take second place to efficient distribution pricing[19]

(b) MEUG expressed the view that *"timing of significant changes to TPM needs to consider both long and near term impacts"* especially given the on-going effects of the Global Financial Crisis.[20]

[19] DEUN submission, p. 9

[20] MEUG submission, p. 7

4. Context: Process for reviewing the TPM (Question 2)

4.1 Overview: Process for reviewing the TPM

4.1.1 The Authority outlined its process for reviewing the TPM, including publication and consultation on an issues paper, determination of guidelines and process for Transpower to follow in preparing a revised TPM, and further consultation on the Transpower TPM.[21]

4.2 What the Authority asked

4.2.1 The Authority also sought submitter views on the process the Authority outlined for developing and approving a new TPM. The Authority also asked submitters to describe and explain any variations to the process that they consider desirable **(Question 2)**.

4.3 Feedback: Process for reviewing the TPM (Question 2)

4.3.1 Overwhelmingly, the consensus view in submissions is that the Authority needs to undertake further consultations given the magnitude of changes being proposed.[22]

4.3.2 In addition, there is a strong desire to see the Authority further engage with industry, particularly through the use of an industry working or advisory group to inform any changes to the current TPM.[23]

4.3.3 In total, 20 submitters provided direct comments on consultation paper Question 2. As with submissions on the materiality of changes, there was a range of opinions.

4.3.4 However, most submitters expressed concern with the current process and argued that some process related amendments were needed. MRP and TrustPower in particular provided extensive comments on the Authority's process to date. The ENA provided comments as to possible next steps (along with others[24]).

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[21] See the consultation paper, p. 33 – 36, paragraphs 2.3.5 – 2.3.8 and 2.3.13 – 2.3.19 for more detail.

[22] See for example submissions from MRP, Meridian, Contact, Norske Skog, Pacific Aluminium, and Pioneer.

[23] See for example Energy for Industy (p. 3), Fonterra (p. 8), MainPower (p. 4), NZCID (p. 2), NZ Steel (p. 2), NZX (p. 2), Pioneer (p. 3), PwC (p. 13), and Orion (p. 3)

[24] See for example, Genesis, although these comments related more specifically to an alternative decision making framework, discussed further below.

4.3.5 The key issues identified as shortcomings by submitters relate to:

(a) Consultations: many submitters expressed the view that, given the complexity of the proposed changes, the timeframe for, and number of, consultations has been insufficient. For example, MRP contended that *" the very compressed timeframes have also meant that consultation forums undertaken by the Authority have not provided meaningful or effective consultation given the fact that so much of the detail of its proposal is yet to be developed and is uncertain"*[25]

(b) Transparency and information flows: some submitters expressed the view that the Authority's process has involved a lack of transparency, and a 'piecemeal' approach to information flows to participants:

(i) Orion expressed the view that it is good that the Authority has extended the deadlines, but that it has become harder over time to get a sense of the coherence of all the material provided. Orion went on to observe that the Authority has not produced an updated version of the paper that relates all the additional information and analysis to its proposal[26]

(ii) MRP suggested that a lack of transparency around the development of the Authority's proposed approach has resulted in participants expending significant time and resources to understand its implications, particularly key aspects such as the CBA and the implementation of the residual charge.[27]

(c) The Authority's impact analysis: there is some submitter concern that the Authority's process in respect of the impact analysis of the proposed changed does not represent regulatory best practice.[28] For example, MRP suggested that *"the decision by the Authority not to release analysis on the range of impacts of its proposals on consumers and suppliers demonstrates a lack of due process"*[29]

(d) Incorporation of industry views: some submissions expressed the view that the Authority has not adequately incorporated the use and views of industry groups in its process.

For example, TrustPower remarked that *"The Authority should have convened another working group similar to TPAG once it finalised its Economic Framework. The group could then have been tasked with developing and assessing options that aligned with the*

[25] MRP submission, p. 51

[26] Orion submission, p. 14

[27] MRP, Appendix A, p. 1

[28] For example, see Vector response to consultation paper Question 2, Appendix I, p. 39.

[29] MRP submission, p. 52

Economic Framework. This would bemore consistent with its usual process."[30]

4.3.6 The Authority notes that there were extensive comments made in response to Question 2 regarding the impacts on consumers, particularly in the context of the costs and benefits of the proposed TPM rather than the actual process. These issues are discussed in more detail in paragraph 4.3.7 below.

4.3.7 A number of submitters provided proposals to amend the Authority's proposed process. These included:

(a) Timing: TrustPower suggested that the time frame for cross-submissions should be extended by one month[31]

(b) That the Authority should conduct further consultations on the proposed changes. Meridian suggested that if the Authority *"…were to make significant amendments to its proposal after receiving submissions and cross-submissions, a further round of consultation would be appropriate"*[32]

(c) That the process needs to include working groups. For example, the ENA suggest that *"…a specialist working group would add value to this next stepby drawing sector expertise and practical experience into the design process directly."*[33] Such a group would operate under clear direction from the Authority, with PwC noting *"given the historical disagreement on the TPM at the TPAG and in other forums, we envisage that the scope of this working group will need to be defined tightly. In particular, to avoid deadlock, the EA will need to provide clear direction on how the HVDC charges should be recovered"*[34]

(d) Uniquely among the submitters, TrustPower requested in its submission the opportunity present its findings on the implications of the proposed TPM to the Authority's Board in a public hearing, prior to any final decisions being made on the TPM[35]

(e) That the Authority should provide further detail on the consequential changes as a result of the proposed TPM. For example, Powerco expressed the view that the Authority needs to outline out how it intends to complete changes to the Benchmark Agreement and Connection Code as a result of changes in the TPM.[36]

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30 TrustPower submission, p. 4

31 TrustPower submission, p. 5

32 Meridian Energy submission, p. 68 ,

33 ENA, submission p. 4

34 PwC, submission p. 13

35 TrustPower submission, p. 5

36 Powerco Limited, *Submission* p. 6-7

5. Decision-making about the TPM

5.1 Overview: Decision-making about the TPM

5.1.1 The Authority has used an economic framework to identify and assess options for the TPM. Briefly, this framework adopts the following hierarchy (from most preferred to least preferred):

(a) market-based charging approaches, being market or market-like charging approaches

(b) exacerbators-pay charging approaches

(c) beneficiaries-pay charging approaches

(d) alternative charging approaches.

5.2 What the Authority asked

5.2.1 The Authority did not explicitly seek submitter views on the decision-making framework. Nonetheless, a small number of submitters provided comments on the Authority's decision-making framework.

5.3 Feedback: Decision-making about the TPM

5.3.1 Two key themes emerged from the eight submitter comments on the decision making framework:

(a) there were some concerns in submissions that the Authority's economic and decision making framework cannot be practicably applied to transmission pricing

(b) some submitters have suggested the Authority has misrepresented the level of industry support for the framework.

5.3.2 The first key theme is the applicability of the Authority's economic and decision making framework to transmission pricing:

(a) a number of submitters expressed the view that the framework cannot be practically applied to transmission pricing. [37] For example, Genesis remarked *"We consider that the Authority's framework for decision-making, while useful, is too high a level to enable detailed and meaningful comparison of TPM alternatives and design choices"*[38]

[37] Genesis, MRP, Norske Skog, Transpower's CEG report and TrustPower

[38] Genesis submission, p. 43

(b) Norske Skog stated that *"by dismissing capacity and offer rights, it is not clear to us that the Authority is following its own principles and framework"*[39]

(c) however, there was some support for the application of the framework. MEUG's consultant, NZIER, noted that *"the proposal flows logically from the economic and decision making framework for evaluating a TPM that the EA consulted on early in 2012."*[40]

5.3.3 The second key issue was the representation of industry support for the framework:

(a) both the ENA and MRP raised concern that the Authority's framework does not, in fact, have widespread industry support. For example, MRP commented *"The Authority's claims in public forums that industry supported its decision making and economic framework for Transmission is a fundamental misrepresentation of participants' views"*[41]

(b) two submitters who explicitly provided comments on the decision making framework expressed a contrary view

(i) MEUG took the position that *"the decision-making and economic framework decided in 2012 is, however, still sound"*[42]

(ii) Pacific Aluminium noted *"the Authority has a well developed and well articulated framework for evaluating these trade-offs, the use of which has led to it to develop its proposal to this stage."*[43]

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39 Norske submission, p. 2

40 NZIER analysis for MEUG submission, p. 16

41 MRP submission, p. 53

42 MEUG submission, p. 2

43 Pacific Aluminium submission, p. 1

6. Problem definition: does the current TPM promote overall efficiency (Question 3 to 15)

6.1 Overview: Problem definition

6.1.1 As a result of applying its economic and decision making framework, the Authority has identified several aspects of the current TPM that it considers are not consistent with promoting the long-term benefits of customers. Application of this framework identified problems in a number of problem areas in the current TPM.

6.2 What the Authority asked

6.2.1 In defining the problem, the Authority sought feedback on:

(a) the nature and materiality of problems with the connection charge, component of the current TPM

(b) the nature and materiality of problems with the HVDC charge and interconnection charge components of the current TPM

(c) the nature and materiality of problems with the approach for recovering the costs of network reactive support services

(d) the prudent discount policy and issues associated with the risk of inefficient bypass or disconnection from the grid.

6.2.2 Specifically, the Authority posed the following questions:

(a) for problems with the connection charge:

(i) do you agree with the Authority's view that the arrangements under the TPM for recovering connection costs are generally efficient? Explain your answer **(Question 3)**

(ii) what comments do you have about the potential for inefficient outcomes to arise from incentives to shift connection costs into the interconnection charge? **(Question 4)**

(iii) do you agree that there is the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract? Explain your answer **(Question 5)**

(iv) do you consider that there are any other problems with the connection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem **(Question 6).**

(b) for problems with the HVDC charge:

(i) what comments do you have about the Authority's analysis of the private benefits deriving from the HDVC link? **(Question 7)**

(ii) what comments do you have about the consequences of the material differences between private benefits from the HVDC link and HVDC charges? **(Question 8)**

(iii) what comments do you have about the Authority's analysis of the costs of inefficient generation investment resulting from the HVDC charge? **(Question 9)**

(iv) what comments do you have about the Authority's analysis of the costs of inefficient operation of South Island generation resulting from the HVDC charge? **(Question 10)**

(v) Do you consider that there are any other inefficiencies arising from the HVDC charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the inefficiencies **(Question 11).**

(c) for problems with the interconnection charge:

(i) What comments do you have about (a) the differences (including their materiality) between private benefits from interconnection assets and interconnection charges and (b) the consequences of those material differences? **(Question 12)**

(ii) What comments do you have about the Authority's analysis of the problems with interconnection charges? **(Question 13)**

(iii) Do you consider that there are any other problems with the interconnection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem **(Question 14).**

(d) for problems with the prudent discount policy and inefficient disconnection:

(i) what comments do you have about the Authority's view that a prudent discount policy may be necessary after taking into account the incentives provided by the price components of any revised TPM? **(Question 15).**

6.3 Feedback: Problem definition

6.3.1 The dominant theme to emerge from relevant submitter comments was that the Authority failed to adequately prove that there is a problem with the current TPM that needs addressing, and that the Authority's views lacked robust supporting analysis.

6.3.2 More specifically, submitters commented that there was a lack of supporting analysis applied to both the Authority's problem definition at a high level and also to specific sub-components of the Authority's problem definition.

6.3.3 For example, while ten of 13 submitters considered there was inefficient operation of South Island generation due to the current HVDC charges, five submitters took the view that such inefficiencies are not likely to have a material cost. Only two out of 11 submitters considered that there were material differences between interconnection charges and private benefits arising from interconnection assets.

While some submitters concluded that a problem exists with HVDC charges, some parties considered it has not been established that the problem is particularly material.

Problems with the connection charge

6.3.4 In response to the Authority's discussion of the problems with current connection charges:

(a) there was widespread opinion that arrangements under the current TPM are already efficient

(b) only a few submitters identified additional problems beyond those identified in the consultation paper

(c) support for the Authority's view on inefficiencies from timing and shifting of connection costs was limited.

Efficiency of current arrangements (Question 3)

6.3.5 14 submitters provided direct answers to consultation paper Question 3. There was almost unanimous agreement (13 submissions) with the Authority's view that the arrangements under the current TPM for recovering connection costs are generally efficient.[44]

6.3.6 Other submitters also provided general comments on the efficiency of current arrangements:

(a) PwC took the view that connection charges are operating efficiently and effectively, and that the issues highlighted by the Authority *"…are generally immaterial and amendments are not required."*[45]

(b) similarly, Alinta noted that *"…it is not clear to Alinta how the new arrangements are likely to improve on the status quo for load or generation."*[46] This position was echoed by Meridian: *"While some*

[44] See submissions from CHH, Clearwater Hydro, Contact, MEUG, Meridian (p. 24), MRP (Appendix A, p. 1), Norske Skog (p. 7), Nova (p. 6), NZ Steel (p. 9), Pacific Aluminium (p. 12), Powerco (p. 7), Transpower (Appendix A, p. 1), TrustPower (p. 8)

[45] PwC submission, p. 11-12

[46] Alinta submission, p. 1

improvement can be made at the edges of the charge, there will be little benefit from wholesale changes."[47]

(c) The EMA consider *"there is really nothing much wrong with the existing transmission pricing system, and no real need for urgency to change it."*[48]

(d) The ENA noted that *"in practice, the existing arrangements and rules have been adequate to handle the situations that have arisen and we believe this is likely to be the case in the future. On that basis we do not consider the proposed change iswarranted."*[49]

6.3.7 Reasons provided in support of the efficiency of the current arrangements include that they provide price stability, efficient investment and a particular level of service. For example:

(a) Clearwater Hydro stated *"recovery of connection charges as proposed appears to be efficient. Provides Transpower with the required return, provides price stability and it is not avoidable and forces users to consider how much they value any new investment prior to the investment being made"*[50]

(b) Transpower expressed the view that *"this approach is consistent with the concept that connection asset customers are purchasing a level of service, rather than a specific set of assets. This approach also supports our ability to optimise capital and operating expenditure across our assets"*[51]

(c) Smart Power contended that the current arrangements are efficient *"…for the reasons set out in your document."*[52]

6.3.8 Two submitters, Meridian and Powerco expressed qualified support for the view that current arrangements are not efficient:

(a) Meridian consider that the efficiency is considerably limited in practice, and a *"…a more robust approach (in both longevity and efficiency terms) would be to have connected parties face the full costs of the actual assets used to connect them"*[53]

(b) Powerco noted that the ability of offtake customers and Transpower to negotiate price-quality trade-offs is constrained due to the application of the economic limb of the investment test, and the consultation paper did not explain this requirement.[54]

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47 Meridian submission, p. 24

48 EMA submission, p. 4

49 ENA submission, p. 26

50 Clearwater Hydro submission, p. 1

51 Transpower submission, Appendix A, p. 1

52 Smart Power submission, p. 2

53 Meridian submission, p. 24

54 Powerco submission, p. 7

6.3.9 Only one submitter, Orion, expressed a contrary view. Orion did not agree with the Authority's view on the efficiency of the TPM, and is of the view that *"…there are still material boundary issues regarding whether assets are classified as connection or interconnection."*[55]

Potential inefficiencies from shifting connection costs into interconnection charge (Question 4)

6.3.10 11 submissions provided answers directly to this question.[56] Five submitters agreed with the Authority that there is the potential for inefficient outcomes to arise from incentives to shift connection costs,[57] four disagreed,[58] and two were non-committal.[59]

6.3.11 A common theme expressed in submitter answers was in relation to whether or not there was a material problem that needed addressing, and that the consultation paper did not provide adequate supporting information for the Authority's position:

(a) CHH observed *"…that while this has been raised as an issue to be resolved, and two potential examples have been noted, there appears to have been no attempt to quantify the problem from an overall NZ inc viewpoint in order to determine its materiality. I.e. is there an estimate of the value of assets built in the last 10 yrs that should more properly have been connection rather than interconnection assets?"*[60]

(b) MRP took the position that *"we do not consider the Authority's analysis is significant robust or the magnitude of potential inefficiencies (if indeed they do exist) to be material enough to justify the complexity of the proposal, particularly given the significant distortions it will create that haven't been quantified"*[61]

(c) similarly, Transpower noted *"there is no evidence that there is a material problem to resolve."*[62]

6.3.12 A few submitters also commented on the need to maintain flexibility in whatever approach is taken by the Authority:

(a) Meridian submitted that the approach to fixing classification of existing assets appears appropriate, but cautioned that there should

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55 Orion submission, p. 14

56 See submissions from MEUG, Pacific Aluminium (p. 13), CHH (p 4), Clearwater Hydro (p. 1), Contact (p. 23), Meridian (p. 24), MRP (Appendix A, p. 1), Powerco (p. 7), Smart Power (p. 3), Transpower (Appendix A, p. 2), TrustPower (p. 8-9),

57 See submissions from MEUG, Pacific Aluminium, Contact , Meridian and TrustPower

58 See submissions from MRP, Powerco, Smart Power and Transpower

59 See submissions from CHH and Clearwater Hydro

60 CHH submission, p. 4

61 MRP submission, Appendix A, p. 1

62 Transpower submission, Appendix A, p. 2

be flexibility for the classification to be changed to reflect the use of the assets, particularly if it is due to circumstances outside of the DTC's control[63]

(b) Smart Power suggest that *"it is hard to imagine that there can be a hard and fast rule which can be put in place to get an ideal solution at all times"*[64]

(c) Transpower considered that *"rather than change to an untested approach of 'locking in' connection asset classification, the status quo should be retained."* This view was on the basis that *"there is a risk that the proposed change could have perverse or unintended consequences if a situation arose where it legitimately made sense for assets to change from connection to interconnection."*[65]

6.3.13 In addition to the potential limitations arising from a lack of flexibility, TrustPower expressed the view that *"the reclassification rule is problematic as it may provide incentives for customers to argue against efficient asset replacement."*[66]

6.3.14 In relation to the proposed dispute mechanism, TrustPower expressed the desire to better understand the process, and submitted that it *"it is not clear whether or not the Authority is reserving to itself the ability to relieve any party of the incidence of connection charges, or who will pay for the shortfall."*[67]

Inefficient outcomes from timing of connection asset replacement (Question 5)

6.3.15 14 submissions provided direct answers to question 5. Eight submitters agreed[68] with the Authority's view that there is the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract. Four submitters disagreed,[69] and two were non-committal.[70]

6.3.16 Answers in agreement with the Authority view generally lacked detailed reasoning, although some did explain their answers. For example, Meridian responded *"Yes. This is primarily due to the detailed methodology used. In order for efficient investment decisions to occur the real costs (asset charges*

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63 Meridian submission, p. 24

64 Smart Power submission, p. 3

65 Transpower submission, Appendix A, p. 2

66 TrustPower submission, p. 8

67 TrustPower submission, p. 8-9

68 See submissions from Contact , MEUG, Meridian, Norske Skog, NZ Steel, Orion, Pacific Aluminium and Smart Power

69 See submissions from CHH, MRP, Powerco and Transpower

70 See submissions from Clearwater Hydro and TrustPower

and maintenance costs) of each specific asset should be reflected in the charge. The Authority's proposal goes some way to alleviate the issue and is a good step forward."[71]

6.3.17 Further, some of the submitters that agreed with the Authority's view expressed only qualified agreement. For example:

(a) Pacific Aluminium responded *"Yes, but if this is as significant an issue as the paper implies, surely the answer is to update the asset values that are used in the building blocks"*[72]

(b) Contact took the view *"Yes, but it is also the right of a connected party not to approve enhancements to existing assets and instead opt to wear the lower reliability."*[73]

6.3.18 Comments disagreeing with the Authority's position in relation to the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract were generally more substantive:

(a) CHH submitted that customers may hold out for a variety of reasons, rather than just because they wish to reduce their specific costs. For example, customers may *"…hold out because they do not agree to major capital expenditure on the connection assets because, for exampletheir future needs are not clear and so may have an alternative proposal that may include enhanced maintenance, monitoring and refurbishment of the existing equipment to extend its life"*[74]

(b) Transpower explained there was no potential for inefficient outcomes to arise and *"there has not been a problem in practice with customers inefficiently avoiding CIC charges"* and that it is not Transpower practice to shift costs from the connection pool to the interconnection pool as part of a major grid investment:[75]

(i) Transpower went into some detail to explain that *"The historic building block values used to assess a customer's charges are only used as a way of allocating the connection pool. The overall size of the connection pool is based on the aggregate regulatory asset value of all connection assets. This means there is no material problem caused by building block values being lower than current replacement costs. Full connection asset costs are recovered from connection customers."*[76]

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71 Meridian submission, p. 24

72 Pacific Aluminium submission, p. 13

73 Contact submission, p. 23

74 CHH, p. 5

75 Transpower, Appendix A, p. 2

76 Transpower, Appendix A, p. 2

(c) Transpower's position was affirmed by Powerco who submitted that *"we do not believe the current arrangements create the potential for an inefficient outcome or that there are any meaningful incentives to "hold out" in order to get connection assets included in a capital expenditure proposal from Transpower to the Commerce Commission. We also note that no such instances have occurred to date."*[77]

6.3.19 At a higher level, TrustPower raised the issue of grandfathering of existing arrangements noting *"the consultation paper does not explain how this (the Authority's proposal to change the method by which investment proposal charges are allocated) would work for parties who are currently paying for assets on an average asset life basis. Would existing arrangements be grandfathered?"*[78]

6.3.20 Clearwater Hydro and TrustPower were non-committal in their answers. Clearwater Hydro responded that *"Clearwater Hydro isn't affected by this. Transpower is capable of managing this process."*[79] TrustPower reiterated its concerns about the how the dispute mechanism or referral provisions would work in practice: *"Again, it is difficult to comment on this proposal without understanding how the dispute or referral provisions will work in practice. For example, will other parties have the opportunity to make submissions on a request for a reduction in charges?"*[80]

Other problems with connection charging arrangements (Question 6)

6.3.21 14 submissions provided answers directly to consultation paper Question 6.

6.3.22 The majority of submitters (10) that provided a direct answer responded that they do not consider there are any other problems with the connection charging arrangements under the current TPM:[81]

(a) MRP, for example, responded *"We consider the current connection charging regime is robust and should not be altered"*[82]

(b) similary, TrustPower's response was simply *"No. The current 'deep connection' approach has proved durable for connection assets."*[83]

6.3.23 The remaining submissions responded that there are other problems with the connection charging arrangements under the current TPM:

[77] Powerco, p. 8

[78] TrustPower submission, p. 9

[79] Clearwater Hydro submission, p. 1

[80] TrustPower submission, p. 9

[81] See submissions from CHH, Contact (p. 24), MEUG (p. 8), MRP (Appendix A, p. 2), Norske Skog (p. 8), NZ Steel (p. 10), Pacific Aluminium (p. 13), Powerco (p. 8), Transpower (Appendix A, p. 2), TrustPower (p. 9)

[82] MRP submission, Appendix A, p. 2

[83] TrustPower submission, p. 9

(a) Meridian considered there are two additional issues problems with the current connection charging arrangements:

(i) firstly, that *"the current mechanism is very opaque and it is hard to track costs from specific assets through to charges. The translation between actual assets to ODV building blocks and then to the asset values attributed to the building blocks are all subject to undocumented variances. There appears to be no standardisation of the process nor valuation. This makes the efficiency of the connection charge questionable. This would be straight forward to correct, but would involve some transitional costs to implement"*[84]

(ii) second, *"There are also inefficiencies introduced due to injection customers facing the overhead charges on connection assets. With the proposed changes to the interconnection charge regime, the treatment of overhead charges should be improved by making it consistent between offtake and injection customers."*[85]

(b) Orion believe there could be improvements made to the way Transpower carries out allocation of shared connection costs, citing its experience at Coleridge where *"assets are clearly largely there to support the connection of the local generation. Yet, because most of the assets are classified as interconnection, and because Orion happens tosupply a few small customers, the connecting generator picks up only around 10% of the cost of what are very specific local assets"* Orion did comment that *"however,this is a comparatively minor issue, and we do not know how often it occurs in other areas."*[86]

6.3.24 Smart Power suggested that *"One possible problem is that if network companies wish to build and own some of these assets themselves so that they get a return on the assets. The problem would arise when the best investment decision for the Network Company may not be the best result for end users. For instance if Transpower is able to access lower financing rates then it could be the more cost effective owner as far as the consumer is concerned. We would be interested in safe guards to ensure that the best investment decision for the end user is made."*[87]

The Authority's analysis of private benefits deriving from HVDC link (Question 7)

6.3.25 14 submissions provided answers in response to consultation paper Question 7. Broadly, submitter answers:

84 Meridian submission, p. 25

85 Meridian submission, p. 25

86 Orion submission, p. 15

87 Smart Power submission, p. 4

(a) expressed the view that there are gaps in the Authority's analysis

(b) provided comments on the Authority's analysis or expressed views on the Authority's position

(c) raised other general issues. Some submitters expressed the view that the Authority's analysis had gaps that required further analysis, including:

(d) consideration of the expectations and asset values of SI generation when they were first established or listed, particularly as it applies to Pole 2[88]

(e) more detail on why the Authority believes the previous decisions on HVDC hasn't worked well[89]

(f) recognition of the *"…very significant reliability and other benefits that a bi-pole solution provides"*[90]

(g) clarity around the extent to which *"…the overriding cause of the mismatch problem is the different treatment of the HVDC and HVAC assets."*[91]

6.3.26 There was some disagreement with the Authority's position around expected outcomes and efficiencies.

(a) Vector commented that it *"does not agree with the Authority's assessment of supposed problems with the current HVDC charges. The Authority's assessment draws on the previous deficient work by TPAG."*[92]

(b) DEUN submitted that *"The dynamic efficiency argument aims to reduce lobbying by those paying for subsequent HVDC upgrades. "Lobbying" is better reduced by means of well-designed regulatory process."*[93]

(c) MRP *"…agree the current HVDC link transmission cost allocation creates inefficiencies"…*but…*"do not agree there will be efficiencies from the Authority's proposed SPD method or residual charge…"*[94]

6.3.27 Meridian supported the Authority's analysis commenting that *"we are now past the point of dispute about whether the HVDC charge is inefficient. Three separate analyses (TPAG, Authority review of TPAG using LRMC-stack model, and Authority GEM analysis)show the HVDC charge to be materially inefficient"*. According to Meridian *"The nature and extent of the*

88 See CHH submission, p. 5 and MEUG submission, p. 9

89 Smart Power submission, p. 5

90 Transpower submission, Appendix A, p. 2

91 Meridian submission, p. 28

92 Vector submission, p. 19

93 DEUN submission, p. 9

94 MRP submission, Appendix A, p. 2

total inefficiencies of the HVDC charge are such that a change to the status quo is necessary if the Authority is to act consistently with its statutory objective."[95]

Consequences of the material differences between private benefits from the HVDC link and HVDC charge (Question 8)

6.3.28 15 submissions provided answers to consultation paper Question 8.

6.3.29 There was no clear consensus emerging from responses, with answers variously querying if there are in fact material differences, and querying the validity of the Authority's analysis and what the consequences of the material differences (where present) are.

6.3.30 Five submissions expressed the view that there are material differences in benefits from the HVDC link and charge.[96]

6.3.31 Two submitters queried whether the differences were material enough to justify needing attention:

(a) DEUN consider that *"a society that considers electricity a benefit to society as a whole will accept 'material differences' in benefits without counting the dollars accruing to separate participants."*[97]

(b) similarly, MEUG is not convinced issues are significant enough to warrant changes, given the forecast of flat demand and little need for large increments of generation. Aside from that, MEUG believe the benefits to South Island generators are materially above the current HVDC charges.[98]

6.3.32 Some submitters responded that the Authority has not provided sufficient evidence to support its analysis of the differences, and disagreed with the Authority's position. For example:

(a) Norske Skog responded *"the Authority has not explained why there is significant economic cost from the current regime…"*[99]

(b) similarly, Vector responded that it disagrees with the Authority's analysis of the impact of current HVDC pricing and that *"…the current HVDC prices satisfy the Authority's decision making and economic framework criteria…".*[100]

95 Meridian submission, p. 26

96 Contact submission, p. 24, CHH submission, p. 5, DEUN submission, p. 10, MEUG submission, p. 8Meridian submission, p. 28

97 DEUN submission, p 10

98 MEUG submission, p. 8

99 Norske Skog submission, p. 9

100 Vector submission, p. 40

6.3.33 Answers also provided some comment on the possibility of reduced disputation or lobbying costs under the proposed TPM, and the impact this would have on transmission investment:

(a) Meridian responded that it *"…agrees with this assessment, but would add that the mismatch is the principal reason why the current TPM is unstable and is currently subject to review. Without a change to this arbitrary allocation of costs, history suggests there will continue to be a substantial amount of what the Authority terms "disputation costs"*[101]

(b) Powerco added that *"…we do not agree with the Authority's view that changes to the incentive to lobby will result in different HVDC investment outcomes in the future as there is no proposed change to the administrative basis of investment decision making, in particular the Investment Test."*[102]

The Authority's analysis of the costs of inefficient generation investment (Question 9)

6.3.34 12 submissions contained a direct answer to consultation paper Question 9.

6.3.35 Eight submitters provided answers expressing agreement that there was inefficient generation investment as a result of the HVDC charge. [103] Without commenting on the size of the costs of inefficient generation investment:

(a) Clearwater Hydro responded they *"Agree the current HVDC charging regime can lead to inefficient behaviour. Spreading HVDC costs across the entire market will remove these incentives."*[104]

(b) Smart Power commented *"Agree this has been an issue with the existing charging regime which seems to be an unnecessarily blunt tool for allocating the cost of the HVDC and we agree that it is a distortion in generation investment decisions and the running of South Island plant. This has been an area of a major discontent for quite some time and not without reason."*[105]

6.3.36 Four submitters who agreed that there were inefficiencies in generation investment due to HVDC charge provided comments on the size of the inefficiency:

(a) MRP answered *"…TPAG noted they are relatively modest and therefore simple and understandable approaches to address them should be favoured that do not introduce wider distortions to the*

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101 Meridian submission, p. 28

102 Powerco submission, p. 9

103 See submissions from Contact (p. 24), MRP (Appendix A, p. 2), Clearwater Hydro (p. 5), Nova (p. 6), Meridian (p. 28), Smart Power (p.5), Transpower (Appendix A, p. 3) and TrustPower (p. 11)

104 Clearwater Hydro submission, p. 2

105 Smart Power submission, p. 5

electricity market. The Authority's proposal does not meet this criteria and will create wider inefficiencies"[106]

(b) Nova *"…agree that there are issues with the HVDC charge as it stands, but that is not sufficient reason to eliminate it entirely. SI generators should still be required to make a specific contribution towards the HVDC costs as they do receive a recognisable benefit that is not adequately covered by other charges (current or proposed)"*[107]

(c) Meridian agreed with the Authority's position that the current HVDC incentivises inefficient generation investment and that this is a *"substantial inefficiency"*. They considered that *"current HVDC charge creates an additional barrier to entry in the South Island for generators, as currently every new South Island generation project must pay an additional HVDC charge. This cost is inefficient at a national level"*[108] and *"…the generation capital cost saving from removing the HVDC charge is approximately $30m ie $2-3/MWh"*[109]

(d) Transpower expressed the view that the various underlying assumptions used to estimate the costs of inefficient generation investment are uncertain but that the TPAG analysis is the best available guide.[110]

6.3.37 Of the four submissions that did not expressly agree with the Authority's view on the presence of inefficiencies in generation investment, two submitters presented the same arguments from their consultant report and the remaining two each identified different issues:

(a) MEUG referenced a report prepared by the NZIER which took the view that *"the current HVDC charge has no (or no material) impact on generation investment and consumer prices and there is no real resource cost, meaning that a benefit based charge would simply result in a wealth transfer and no useful additional price signals and no gains in dynamic efficiency"*[111]

(b) CHH also stated that *"…a more convincing analysis would include data and analysis on investments in SI generation over the past few years and evidence of investments that have not (or even claimed to have not)taken place due to HVDC link charges"*[112]

(c) Norske Skog reiterated its previously stated view that *"…new South Island generators should not have to pay any HVDC charges. This*

106 MRP submission, Appendix A, p. 2

107 Nova submission, p. 6

108 Meridian submission, p. 28

109 Meridian submission, p. 29

110 Transpower submission, Appendix A, p. 3

111 NZIER for MEUG's submission, p. 9

112 CHH submission, p. 5

overcomes any real or perceived generation investment inefficiency"[113]

(d) Pacific Aluminium answered *"if this is a serious issue then the obvious solution is to ringfence the HVDC charges to existing SI generation with no new SI generation investment attracting HVDC charges. Given recent announcements of SI investment deferrals in the light of flat demand, this is much less likely to be an issue now."*[114]

The Authority's analysis of the costs of inefficient operation of South Island generation (Question 10)

6.3.38 13 submitters provided a direct answer to consultation paper Question 10.

6.3.39 Ten submitters agreed that there are inefficiencies in the operation of South Island generation associated with the HVDC charge. [115]For example:

(a) Nova answered *"We concur with the view that note that an RCPI charge has the effect of creating a higher marginal cost of generation, which is likely to occur during periods of very high hydro inflows"*[116]

(b) similarly, Transpower stated *"We agree the HAMI charge causes some inefficiency on the operation of South Island generation"*[117]

(c) Smart Power's agreed *"…this has been an issue with the existing charging regime which seems to be an unnecessarily blunt tool for allocating the cost of the HVDC and we agree that it is a distortion in generation investment decisions and the running of South Island plant."*[118]

6.3.40 However, five submitters took the view that such inefficiencies are not likely to have a material cost.[119]

(a) CHH said the costs would only have a *"minor effect at best. More likely immaterial or nil effect."*[120]

(b) MRP stated *"We agree the inefficiencies exists but as the figures show and TPAG noted they are relatively modest and therefore simple and understandable approaches to address them should be*

113 Norske Skog submission, p. 9

114 Pacific Aluminium submission, p. 14

115 See submissions from Contact (p. 24), Meridian (p. 29), MRP (Appendix A, p. 2), Norske Skog (p. 9), Nova (p. 7), Pacific Aluminium (p. 14), Powerco (p. 9), Smart Power (p. 5), Transpower (Appendix A, p. 3), TrustPower (p. 11)

116 Nova submission, p. 7

117 Transpower submission, Appendix A, p. 3

118 Smart Power submission, p. 5

119 See submissions from CHH (p. 6), DEUN (p. 10), MEUG (p. 9), MRP (Appendix A, p. 2), Pacific Aluminium (p. 14)

120 CHH submission, p. 6

favoured that do not introduce wider distortions the electricity market. The Authority's proposal does not meet this criteria and will create wider inefficiencies."[121]

(c) Pacific Aluminium responded *"it is inevitable that a charging structure like the HAMI will distort dispatch at the margins. The question that has not been answered is whether or not this distortion is so serious that it warrants a change to the structure of the charge. The analysis to date suggests not."*[122]

Other inefficiencies arising from current HVDC charging arrangements (Question 11)

6.3.41 12 submitters provided a direct answer to consultation paper Question 11.

6.3.42 Two submitters, Meridian and TrustPower, provided answers identifying other inefficiencies arising from the HVDC charging arrangements under the current TPM:

(a) Meridian suggested an additional inefficiency is *"…the arbitrary different treatment of the HVAC and HVDC assets contributes to the TPM being unstable and not durable". "In a longer term context, it is hard to quantify the costs of unprincipled regulatory decision-making in the sector, but there will be a detrimental impact on investor perceptions"*[123]

(b) TrustPower said that the consultation paper does not appear to cover the issue that *"The allocation mechanism for the HVDC costs would favour new generation investment in the SI by large incumbent SI generators, relative to small incumbent generators or new entrants if those new investments by the large incumbent are more likely to delay alternative NI rather than SI investments by competitors."*[124]

6.3.43 Nine submitters considered that there are no other inefficiencies arising from the HVDC charging arrangements under the TPM.[125]

Problems with the interconnection charge

6.3.44 In relation to the Authority's discussion of problems with the interconnection charge, there was generally limited support for the Authority's position, and a reasonably widespread view that further analysis of problems with the interconnection charge are needed to support the Authority's position.

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121 MRP submission, Appendix A, p. 2

122 Pacific Aluminium submission, p. 14

123 Meridian submission, p. 29

124 TrustPower submission, p. 11-12

125 See submissions from Contact (p. 25), DEUN (p. 10), MEUG (p. 9), MRP (Appendix A, p. 2), Norske Skog (p. 9), NZ Steel (p. 10), Pacific Aluminium (p. 15), Pioneer (p. 8), Transpower (Appendix A, p. 3)

Materiality and consequences of differences between private benefits from interconnection assets and charges (Questions 12a and 12b)

6.3.45 11 submitters provided comments in direct response to consultation paper question 12(a).

6.3.46 Two submissions took the view that there are material differences between private benefits from interconnection assets and charges:

(a) MEUG responded *"We agree there are significant differences between what some parties pay for transmission services under the existing TPM and the benefits they receive. In some cases the difference is negative and in other cases positive"*[126]

(b) Pacific Aluminium commented *"It is very clear that many beneficiaries of investment in the interconnected grid do not bear an efficient cost for this investment. This results in other consumers inefficiently bearing costs that potentially greatly exceed their private benefits"* but this *"…is a predictable outcome of a methodology that focused on maximising static efficiency given the expectation of little grid investment. This expectation changed a decade ago but the TPM inappropriately remained largely static."*[127]

6.3.47 The remaining submissions broadly took the view that there is no material difference between private benefits from interconnection assets and charges. For example:

(a) Smart Power said *"We agree that there is a misconstruct between the private benefits from the assets and the way in which they are currently charged for. From a non-direct connect end users perspective in most cases the differences are sufficiently diluted to avoid any major distortion of behaviour"*[128]

(b) Powerco's view is that *"We do not place much store by the dollar values estimated. With respect to the suggested inefficiency of transmission investment relative to a beneficiaries pay charge, we suggest this figure should be zero, as the administrative arrangements governing grid investment (in particular, the Investment Test) will not change and we doubt that the incentive to provide additional information to the Commission and to lobby it (which is the mechanism the Authority believes would achieve the greater efficiency) is likely to result in different investment approval outcomes."*[129]

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126 MEUG submission, p. 9

127 Pacific Aluminium submission, p. 15

128 Smart Power submission, p. 5-6

129 Powerco submission, p. 9

(c) Clearwater Hydro's position was that it does *"…not consider any distortion significant."*[130]

6.3.48 Further, some submissions queried the issue at a more conceptual level. For example:

(a) MRP responded *"The Authority's analysis is not sufficiently robust to allow participants to form a reasonable view on these questions." "The identification of private beneficiaries is problematic as it does not accord with the national benefit approach considered by the Commerce Commission to invest in the assets in the first place"*[131]

(b) Orion contended *"The real question is whether the stated benefits are meaningful. If NZ has indeed made a number of poor large sunk cost investment decisions, then clearly that decision-making process should be the direct and primary focus of review. In the current proposal it is not"*[132]

(c) Transpower submitted that *"The Authority has not demonstrated that there are material problems that would warrant a change. While more targeted beneficiary pays charges may be more desirable in theory, there is value to simple, forecastable, stable approach to recovering interconnection costs"*[133]

(d) TrustPower advised that *"the current interconnection charge recovers costs from off-take customers proportional to the contribution of each off-take customer's RCPD" "signalling of peak usage of interconnection assets is efficient, and likely to deliver significant long-term benefits for consumers. It would be enhanced by the extension of the RCPD methodology to include the HVDC assets. In contrast the Authority is proposing to dilute the RCPD signal."*[134]

6.3.49 There was no clear consensus on the consequences of the material differences, with only six (6) submissions containing a direct answer to consultation paper question 12(b):

(a) Clearwater Hydro said it did *"…not see material consequences of any mismatch"*[135]

(b) DEUN contended that *"the new SPD pricing scheme greatly dilutes the peak load pricing." "this dilution seems to be the most important consequence of SPD pricing"*[136]

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[130] Clearwater Hydro submission, p. 3

[131] MRP submission, Appendix A, p. 3

[132] Orion submission, p. 16

[133] Transpower submission, p. 3

[134] TrustPower submission, p. 12

[135] Clearwater Hydro submission, p. 3

[136] DEUN submission, p. 10

(c) Pacific Aluminium responded that *"the consequences have been some parties paying far more than an efficient cost for grid investments. In particular, generators, who derive significant private benefits from the interconnection assets, currently bear none of the costs"*[137]

(d) TrustPower noted that *"…the Authority has overstated the adverse impact on dynamic efficiency caused by the current interconnection charge."* TrustPower also noted that even if *"people in New Zealand only made perfect transmission investment decisions, at exactly the right times, the difference in total cost between that outcome and what would be expected to arise under a postage-stamp charging regime would be relatively immaterial"*[138]

(e) in addition, TrustPower expressed the view that *"…there is an argument that in New Zealand, the Commerce Commission has already been entrusted with the responsibility of assessing the broad public benefits of particular grid upgrades, and that the existing method of socialising charges for existing transmission assets is itself a valid form of beneficiaries pay charging."*[139]

Authority's analysis of problems with interconnection charges (Question 13)

6.3.50 13 submissions provided substantive answers to consultation paper Question 13, covering a broad range of issues.

6.3.51 A number of answers contained comments in relation to the Authority's analysis itself, while others raised more general policy considerations.

6.3.52 Specific comments on the Authority's analysis included:

(a) not enough value having been attributed to the positive effects of price responses (load control during peaks) under the current regime, *"…and the potentially negative effect of reduction these incentives will have"*[140]

(b) overstatement of the costs as a result of problems with postage stamp charging method. Norske Skog considered that *"…the problems that would arise due to the proposal would be worse than the current regime"*[141]

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137 Pacific Aluminium submission, p. 15

138 TrustPower submission, p. 13

139 TrustPower submission, p. 13

140 Clearwater Hydro submission, p. 3

141 Norske Skog submission, p. 10

(c) a robust causal link between increased pricing-driven grid investment processes and better investment decisions has not been established[142]

(d) bias of the analysis towards a particular solution. Transpower commented *"The Authority's problem definition work for the interconnection charge adopts a "diagnostic" approach. That is, the problems cited are often defined with reference to the Authority's specific proposal. This can lead to an incorrect problem definition and bias the analysis toward a particular solution. Rather, a proposal should be evaluated empirically – not legitimated by definition."*[143]

(e) consideration of efficiency issues:

(i) TrustPower considered that *"…the issues relating to dynamic efficiency are significantly overstated in the Authority's analysis of the problems with the interconnection charge and the analysis fails to place sufficient weight on the reasons for the current approach"* and *"There is also no evidence presented in the Authority's analysis that the current transmission investment decision process is not working efficiently already"*[144]

(ii) TrustPower are also concerned *"…that the Authority's analysis does not fully consider the potential dynamic inefficiency from the reduction in the number of distributors which pay interconnection charges, and the lower level of those charges under the proposed TPM Guidelines. These factors could result in less investment in, and utilisation of, load control capability. This is inefficient."*[145]

6.3.53 Additional comments of a more general nature were made by submitters that did not relate directly to the question of whether submitters agreed with the Authority's analysis of problems with interconnection assets:

(a) the proposed changes could result in increased uncertainty, leading to lower investment and higher consumer prices.[146] Contact , for example, responded *"the Authority's proposal has the potential to increase risk to purchasers reflecting the risk generators face in the form of higher, more volatile wholesale prices."*[147]

(b) The proposed changes are mistimed:

(i) DEUN stated that *"the analysis focuses on dynamic efficiency effects, and so is about a decade too late – the bulk of Transpower*

[142] Transpower submission, Appendix A, p. 4

[143] Transpower submission, Appendix A, p. 4

[144] TrustPower submission, p. 13

[145] TrustPower submission, p. 14

[146] See Clearwater Hydro submission, p. 3 for example.

[147] Contact submission, p. 26

expansion is completed or committed. Efficient charging for remaining projects would give a much smaller benefit than it would have a decade ago, while causing a great deal of effort for any participant to maximise the benefits and/ or minimise its costs to themselves"[148]

(ii) similarly, Contact responded *"…the bulk of the increase in interconnection charges will arise well before any revised TPM has the opportunity to take effect."*[149]

(c) The proposal lacks clarity and supporting evidence. For example:

(i) Transpower commented *"It is also not clear that there could be significant benefits due to "finding better transmission solutions". Grid investment already involves robust, multi-stage consultative processes for which finding the best available solution is a central feature"*[150]

(ii) TrustPower contended *"there is also no evidence presented in the Authority's analysis that the current transmission investment decision process is not working efficiently already"*[151]

(iii) MRP noted *"we do not consider the Authority's analysis of the problem is clear or robust."*[152]

6.3.54 There were some limited comments in support of the Authority's analysis:

(a) Pacific Aluminium, for example, said *"the Authority's analysis is comprehensive"*[153]

(b) Meridian *"agrees that a change to the HVAC interconnection status quo should be made."*[154]

Other problems with the current interconnection charging arrangements (Question 14)

6.3.55 13 submissions provided direct answers to consultation paper Question 14, with a mix of answers between answers that identified additional problems with the current TPM interconnection charges, and those that considered no changes were necessary, or there were no additional problems.

6.3.56 Nine of the direct answers took the view that there were no other problems with the interconnection charging arrangements under the current TPM. For example:

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148 DEUN submission, p. 11

149 Contact submission, p. 26

150 Transpower submission, Appendix A, p. 4

151 TrustPower submission, p. 13

152 MRP submission, Appendix A, p. 3

153 Pacific Aluminium submission, p. 15

154 Meridian submission, p. 30

(a) Clearwater Hydro responded that *"…the current interconnection charge is good. It provides strong incentives to manage peak demand which governs system capacity. It is transparent and generally well understood. It provides a real incentive to control load. The cost of the interconnection charge while not fixed is certainly predictable and systems have been developed to make it manageable. Trade-offs can be made between costs and service level."*[155]

6.3.57 Further, some submitters expressed the view that no changes at all are needed to the current TPM:

(a) MRP expressed the view that *"we do not consider the Authority has sufficiently demonstrated there are material issues…"*[156]

(b) Transpower answered *"No. There is no evidence of material problems with the current interconnection regime"*[157]

(c) TrustPower stated that they believe *"…it is very important that no change is made to the current TPM that would result in a diluting of the incentives placed on distribution companies to develop arrangements which defer transmission investment."*[158]

6.3.58 Of the four answers that suggested there are additional problems not identified by the Authority, each provided a different issue:

(a) DEUN said *"the biggest problem to us is barely mentioned in section 4 of the consultation paper – it is that it dilutes the peak management incentive. This may be barely relevant in locations where there is excess transmission capacity, BUT it is still relevant in many or most distribution networks"*[159]

(b) MEUG considered that *"…the failure of the existing interconnection charges to complement the investment decision making process to avoid uneconomic assets being built. We believe that it is critical that grid planning and transmission pricing are conducted in tandem and are tightly synchronised"*[160]

(c) Norske Skog commented *"the main problem with postage stamp pricing is that causers of transmission investments can pass the costs onto others. There are other ways (than the proposal) to look at solving this problem if it is deemed serious enough"*[161]

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155 Clearwater Hydro submission, p. 3

156 MRP submission, Appendix A, p. 3

157 Transpower submission, Appendix A, p. 4

158 TrustPower submission, p. 14

159 DEUN submission, p. 11

160 MEUG submission, p. 10

161 Norske Skog submission, p.10

(d) PioneerPioneer expressed the view that *"…the Authority does not appear to have given any consideration to the contribution of embedded generation to the efficient operation of the electricity market."*[162]

Problems with the prudent discount policy and inefficient disconnection

6.3.59 In relation to the Authority's discussion of the prudent discount policy, there was widespread support from submitters that it was necessary to continue with a prudent discount policy. Some submitters suggested amendments should be made going forward.

Necessity of a prudent discount policy (Question 15)

6.3.60 16 submissions provided answers directly to consultation paper Question 15.

6.3.61 There was near unanimous support (14 answers) at a high level for a prudent discount policy to be part of any revised TPM. Reasons given for needing a prudent discount policy included:

(a) to avoid inefficient load mitigation/disconnection from the grid[163]

(b) any change to the price components of any revised TPM will warrant a prudent discount policy[164]

(c) to provide incentives for generation in pragmatic logical locations[165]

(d) to facilitate innovative demand-side options to address peak demand.[166]

6.3.62 The ENA and PwC also took the view that it was necessary to continue with a prudent discount policy. The ENA, for example, responded *"the ENA supports continuing the PDP and extending the duration of a PDP up to the expected life of the assets involved. We also support in principle widening the scope of the PDP to include generation investments, subject to reviewing the way in which this wider scope is implemented."*[167]

6.3.63 Submissions in support of a prudent discount policy also provided comments as to necessary design features or considerations of the policy:

(a) Meridian's answer cautioned that *"It is important, then, that the prudent discount policy ensures only credible business cases for alternative projects are eligible for the prudent discount. Meridian understands that the current process Transpower applies under the*

162 Pioneer submission, p. 9

163 NZ Steel submission, p. 11

164 CHH submission, p. 7

165 Contact submission, p. 26

166 DEUN submission, p. 11

167 ENA submission, p. 24

prudent discount policy to determine whether an alternative project is viable is robust in this regard. This should continue under the revised prudent discount policy"[168]

(b) Orion noted that *"the policy should be clearly stated and consideration should be given to making public any decisions under the policy"*[169]

(c) Pioneer said that the prudent discount policy *"…is not an appropriate methodology for paying owners of embedded generation assets for the benefits accruing to network and transmission asset owners from embedded generation"*[170]

(d) Powerco responded *"with respect to the Authority's comment that it might have expected some uneconomic bypass to have occurred if the bar is set high for prudent discount agreements, we note that there are few commercially attractive opportunities to bypass the grid apart from those that are already subject to pre-existing notional embedding agreements"*[171]

(e) CHH contended that *"the 15 year life of present prudent discount policies is quite arbitrary and a more appropriate solution would be to have the length of a prudent discount policy to coincide with an agreed asset life."*[172]

6.3.64 MRP took the opposite view to the other submitters that provided direct answers, stating *"we did not support in our earlier submissions to the framework on the basis we did not consider it a credible outcome."*[173]

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168 Meridian submission, p. 50

169 Orion submission, p. 17

170 Pioneer submission, p. 9

171 Powerco submission, p. 10

172 CHH submission, p. 7

173 MRP submission, Appendix A, p. 3

7. Proposal: LCE (Question 16)

7.1 Overview: LCE

7.1.1 The Authority proposed to codify a requirement that Loss and Constraint Excess (LCE) income received by Transpower is to be used to offset the components of Transpower's transmission charges that correspond to the origin of rentals. The proposal did not specify the particular methodology for Transpower to use but rather stated that Transpower's methodology for applying LCE to particular assets must have the effect of offsetting transmission charges to the customers of those assets.

7.1.2 The proposed changes were not considered to prevent the introduction of Financial Transmission Rights (FTRs) project as the proposal addressed treatment of funds received by the Clearing Manager but did not specify funds that must be made available to Transpower from the Clearing Manager.

7.2 What the Authority asked

7.2.1 Submitters views on the LCE proposal to codify that LCE or residual LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals **(Question 16)**

7.3 Feedback: LCE (Question 16)

7.3.1 21 submitters commented on the Authority's LCE proposal. Out of those commenting, 13 submitters either supported the proposal or broadly supported the concept of the proposal. 8 submitters did not support the proposal.

7.3.2 ENA supported the principle of offsetting LCE's against transmission charges. However it did not support the proposed method of using the LCEs to off-set the components of the transmission charges that correspond to the origination of the LCE. ENA thought this approach would negate (or at the least reduce) the otherwise efficient wholesale market signals related to losses and congestion. In ENA's view, the most straightforward approach to the off-set would be to deduct residual LCEs from Transpower's overall annual revenue requirement.[174]

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174 ENA submission, p. 7

7.3.3 Powerco likewise supported the concept of the proposal but considered that it would be difficult to achieve in practise because *"the methodology used to rebate the loss and constraint excess does not exactly mirror the TPM"*[175].

7.3.4 Vector supported Transpower retaining residual transmission rentals and auction income from locational hedges (transformed rentals). Vector stated that *"the proposal would be improved if the transformed rentals are not tagged to individual (SPD) assets. The transformed rentals could then be used to reduce the revenue recovered from the remaining components of a pricing methodology i.e. they would reduce the residual charges rather than the SPD charges"*.[176]

7.3.5 MEUG advised that it was *"unsure what policy problem the proposed change is intended to solve"*. MEUG understood LCE or residual LCE sums as a whole would reduce the aggregate revenue requirement then allocated by the SPD allocation and residual allocation methods. MEUG only became aware in February 2013 that the proposal was to net LCE or residual LCE from the revenue requirement of specific assets. MEUG considered that the proposed *"approach will have detrimental effects on options for using LCE or residual LCE for further hedge options to manage Within-Island-Basis-Risk"*.[177]

7.3.6 Fonterra submitted that *"the purpose of the loss and constraint rental is to change consumer behaviour as it increases the price to indicate that the line is constrained. If this rental is placed back against the individual asset, then it could result in the consumer no longer receiving this pricing signal, and may in fact decrease the allocation at that point"*. Fonterra advised that *"the proposed treatment of the loss and constraint rental may have merit, however further clarification and consultation is required on this aspect."*[178]

7.3.7 Norske Skog similarly contended that the proposal *"would appear to water down nodal pricing signals to constrained areas, thus dis-incentivising consumers from taking action to alleviate the constraint"*.[179]

7.3.8 NZ Steel agreed with the proposal generally but *"would not agree to the LCE offset being reduced for FTRs using LCE rentals not related to links between FTR nodes"*. NZ Steel also questioned the application of LCE rentals against individual assets.[180]

7.3.9 TrustPower did not support the Authority's approach, primarily due to the *"volatility and unpredictability that this (offset) introduces into the remainder of the transmission charge that must be recovered by Transpower.*

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175 Powerco submission, p. 10

176 Vector submission, p. 41

177 MEUG submission, p. 10

178 Fonterra submission, p. 6

179 Norske Skog submission, p. 10

180 NZ Steel submission, p. 11

TrustPower's preference to date has been that, under an allocation mechanism, the LCE finds its way back to the loads that paid for it in the first place, preferably via an LRA administered by the Clearing Manager."[181] Nova agreed with TrustPower stating that the Authority's proposal would make *"the net transmission and distribution component of retail costs more volatile"* and concluded that this volatility *"will be reflected in higher retail margins to offset the risk of undercharging"*.[182]

7.3.10 While Contact stated that it did not disagree with the Authority, it stated that *"the allocation of LCE received by Transpower to offset transmission charges may prevent other uses of LCE that are potentially more efficient"*.[183] Genesis agreed with this view.[184]Contact concluded that there was further work required by the Authority (to determine the most efficient use of LCE).[185]

7.3.11 MRP advised that the proposal could lead to complexities such as *"increased loss and constraints across interconnection/HVDC assets reducing the transmission charges some participants would pay via the SPD method and the residual for those assets. Thus when parties structure their bids/offers they will have to consider not just wholesale market price impacts in a trading period but also SPD/residual charge impacts net of LCE rebates, all across a number of assets."*MRP recommended that it supported the continuation of connection LCE being rebated on a *"straightforward gross basis"*.[186]

7.3.12 Genesis submitted that allocating the LCE revenue to the assets that gave rise to them does not appear to have any particular efficiency benefits. It agreed with Norske Skog that this approach may mute wholesale nodal price signals and added that the proposal would preclude use of the revenue to develop intermodal hedge products that would allow retailers to better manage basis risk. Genesis recommended retention of the status quo to *"preserve the crude locational hedge"*.[187]

7.3.13 Pioneer agreed with the Authority that *"it is appropriate that LCE rentals are allocated to assets, and those that pay for those assets, that correspond to the origin of the rentals."* However, Pioneer also advised that *"this first step in the allocation of transmission costs creates the first of many sources of variability in transmission charges payable by companies at each step of the value chain"*.[188]

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181 TrustPower submission, p. 15-16

182 Nova submission, p. 8

183 Contact submission, p. 29

184 Genesis submission, p. [185] Contact submission, p. 29

185 Contact submission, p. 29

186 MRP submission, Appendix A, p. 5

187 Genesis submission, Appendix A, p. 47

188 Pioneer submission, p. 10

7.3.14 Smart Power *"strongly support"* the Authority's LCE proposal, noting that *"the current practice is unsatisfactory as the rentals are passed on in an ad hoc manner which varies from network to network."* Smart Power further advised that *"some of our customers receive the benefits while others do not and for smaller users it just disappears into the pool. In this way although individual payers might not necessarily gain the full benefit it would be much fairer."*[189]

7.3.15 NZX also agreed with the proposal, citing that this would provide certainty to participants. According to NZX, it also *"opens the possibility of direct payment to participants by the clearing manager"* and *"may be more efficient from a cash flow perspective especially if the industry adopts partial net settlement"*.[190]

7.3.16 Transpower, however, did not support this proposal. According to Transpower it would mute nodal pricing signals, which would reduce the efficiency of those signals. In Transpower's view, LCE should be rebated independently of the pricing process, as it is currently. Transpower contended that *"this achieves the same end effect on customers, while avoiding the need to embed an additional monthly input into the price setting process"*.[191]

[189] Smart Power submission, p. 7

[190] NZX submission, p. 6

[191] Transpower submission, p. 5

8. Proposal: connection costs (Question 17 and 18)

8.1 Overview: connection costs

8.1.1 The Authority retained the essential components of the current connection charge although proposed to make amendments to the TPM to close what it considers to be two loopholes. The proposed amendments were as follows:

(a) include a provision that requires current connection assets remain connection assets until they are replaced

(b) include a provision that replacement assets are valued at the actual replacement project cost

(c) allow a connection customer to dispute connection charges and include a mechanism for the Authority to make a determination, and if necessary, adjust connection charges.

8.2 What the Authority asked

8.2.1 Submitter views on the connection charge proposal including whether there were efficiency gains from the proposal **(Question 17)**, and the proposal's ability to address the problem identified in chapter 4 in relation to the connection charge **(Question 18)**

8.3 Feedback: connection costs

Efficiency gains from the Authority's connection charge proposal (Question 17)

8.3.1 22 submitters commented on question 17. 32 submitters did not comment. Of the submitters that made comments, 13 either agreed that there would be efficiency gains associated with the proposal or agreed broadly with the proposal. 9 submitters disagreed.

8.3.2 ENA, on behalf of 29 distributors, advised that the existing connection charge arrangements and rules *"have been adequate to handle the situations that have arisen and webelieve this is likely to be the case in the future"* and that *"countervailing pressures"* existed to prevent undesirable outcomes.[192] ENA also noted that EDBs are able to pass through CIC and connection costs, so distributors *"do not have a financial incentive to take the approach the Authority is concerned about"*.[193] PwCPwC, on behalf of 22 distributors, also did not support the proposed amendments aimed at closing minor loop-holes.

192 ENA submission, p 26-27

193 ENA submission, p 27

PwC commented that it preferred the current approach to connection charges as the issues that the proposal attempted to address were viewed as being either immaterial or irrelevant.[194]

8.3.3 Similarly, Smart Power submitted that the Authority *"is trying to fix an issue which is not a huge problem at present"*[195] while Alinta noted that direct connection charges already provide a clear signal.

8.3.4 Pacific Aluminium agreed with recommendations set out in (a) and (c) above, but did not support the proposed amendment set out in (b) which provides for valuing replacement assets at actual replacement project cost. Pacific Aluminium's objection was that this "*cut across the valuation regime that is the province of the Commerce Commission*" and that as an alternative, the Authority could *"update the regulatory asset values"*.[196]

8.3.5 TrustPower similarly had concerns that about charging for a replacement connection asset on the basis of replacement costs when the previous asset was charged under the average age method.

8.3.6 TrustPower noted that the case for individual referral to the Authority is not strong, as it may lead to a greater number of disputes. TrustPower also noted its concerns around the Authority's proposal to determine levels of connection charges on a case-by-case basis if a party thinks that the connection charging regime results in outcomes contrary to the promotion of the Authority's statutory objective. TrustPower requested further information about how this process would work in practice.[197]

8.3.7 Transpower submitted that the proposal creates more problems than *"the minor issues that it seeks to address:*

(a) Customers would experience 'rate-shock' (going from a pool charge, to a new asset charge) when, to maintain service levels, we carry out end of life asset replacements. This may mobilise opposition to such replacements, which would hinder our ability to maintain services using rational asset management decisions.

(b) Referral of disputes to the Authority would put the Authority back in the position of a second transmission regulator, which is counter to the intent of the reforms that led to its creation. The Commission already regulates expenditure on asset replacements.

(c) *'Locking-in' connection asset status may unnecessarily restrict our ability to efficiency reconfigure the grid in future"*[198]

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194 PWC submission, p. 3

195 Smart Power submission p. 7

196 Pacific Aluminium submission, p.16

197 TrustPower submission, p.16

198 Transpower submission, Appendix A, p. 5

The proposal's ability to address the problem identified in chapter 4 in relation to the connection charge (Question 18)

8.3.8 The Authority received 21 responses to question 18 while 33 submitters declined to comment. Of the submitters that made comments, 12 either agreed that the proposal addressed the problems identified in chapter 4 or broadly agreed with the proposal. 9 submitters disagreed.

8.3.9 Powerco disagreed with the Authority's proposal for connection charges which it believes is based on a misunderstanding of the role of the replacement cost schedule. According to Powerco the *"schedule is purely an allocator, so updating it will have no effect on the connection revenue recovered"*.[199]

8.3.10 According to Powerco *"the connection cost allocation method used by the TPM in effect 'under-recovers' the asset return on newer assets and 'over-recovers' the asset return on older assets, with the net effect being NPV neutral over the full lives of the assets"*.

8.3.11 Powerco also submitted that the Authority *"seems to be under the misapprehension that all connection asset replacements are done pursuant to customer investment contracts (CICs). In fact, many 'like for like' connection asset replacements are not done under CICs and the replaced assets consequently remain in the connection asset pool. We understand that Transpower considers that this approach to replacing assets does not contravene the requirement in clause 36.1(a)(2) of the Benchmark Agreement that it 'not change the connection assets' (other than in accordance with the Agreement), as it believes that 'like for like' replacements does not change the assets."*

8.3.12 Powerco summarised its position by stating that it did not believe the current arrangements *"create the potential for an inefficient outcome or that there are any meaningful incentives to hold out in order to get connection assets included in a capital expenditure proposal from Transpower to the Commerce Commission"* and that "no such instances have occurred to date".

8.3.13 Waipa submitted that the Authority made the statement that: *"Connection is generally a contestable service, in that the connecting party can choose to undertake much of the investment."* Waipa challenged this assumption noting: *"Our current experience is that while we have gained Transpower's agreement to build a new 110kV transmission line for Te Awamutu, Transpower will not, under any circumstances permit us to construct or contact with an approved Transpower contractor to construct the connection assets within their GXPs. The EA should ensure connection assets are contestable provided they meet an acceptable engineering standard."*[200]

[199] Powerco submission, p. 10-12

[200] Waipa submission, p 5-6

8.3.14 Vector suggested that a logical evolution of the methodology that would enhance efficiency would be a fine-tuning the of the definition and treatment of connection charges[201] while CHH agreed with the general concept of the changes but suggested that the Authority *"include an ability for the consumer to dispute decisions to replace assets prior to any actual replacement as well as charges arising from asset replacement"*[202]

8.3.15 Business NZ submitted that there should be reliance wherever possible *"on private contracting with directly affected parties for the provision of, payment for, new connection assets and where not possible, allocate the costs of connection assets as fixed charges amongst connected parties."* This is on the basis that *"the prospect of allocation should enhance the prospects for negotiated payments."*[203]

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201 Vector submission, p 3

202 CHH submission, p 7

203 Business NZ submission, p 3

9. Proposal: static and dynamic reactive support (Questions 19 to 22)

9.1 Overview: static and dynamic reactive support

9.1.1 The Authority proposed introducing an exacerbators-pay approach for the recovery costs incurred in providing static reactive support to the grid. The proposal involves applying a kvar charge to off-take transmission customers, at times of RCPD.

9.1.2 The approach involves setting a minimum power factor of 0.95 lagging in the connection Code for all regions.

9.1.3 The Authority proposed recovering costs of dynamic reactive support using the beneficiaries-paying method for HVDC and interconnection assets. It was considered that the beneficiaries of the greater power transfer enabled by dynamic reactive support could be determined by analysis of the situation with and without the dynamic reactive support.

9.2 What the Authority asked

9.2.1 Submitters views on the static reactive support proposal involving the introduction of a kvar charge based on off-take transmission customers' average aggregate kvar draw from the grid in areas where investment in static reactive support is likely to be required, including setting of a minimum power factor of 0.95 lagging in the Connection Code in all regions **(Questions 19 and 20)**, and submitters views on viable alternatives to a kvar charge for recovering the static reactive support costs **(Question 21)**

9.2.2 Submitters views on the dynamic reactive support proposal to use the interconnection charge to recover cost of dynamic reactive support (**Question 22**)

9.3 Feedback: static and dynamic reactive support

Assessment of the Authority's static reactive support proposal (Questions 19, 20, and 21)

9.3.1 25 submitters commented on static reactive support. Of these, nine submitters gave unqualified support for the proposal while 16 submitters supported the concept of the charge but not the detail of the proposal. No parties were opposed to the concept of a kvar charge while 29 submitters did not comment on the Authority's proposal.

9.3.2 The distributors generally accepted the Authority's proposal with their views represented through PwC and ENA submissions. Only Orion was qualified in its support for the proposal, identifying a lack of clarity over the identity of the counterparty to be charged, but assumed it was the off-take party. Orion was supportive of the concept but had some concerns over a risk that some areas would end up paying too much.

9.3.3 Of the gentailers, TrustPower, Nova, Meridian, Might River Power and Contact supported the Authority's proposal. Genesis suggested that the Authority *"review appliance standards and the consumer economics relating to power factor of consumer devices"*[204]. Castalia, in a report provided to Genesis, and included within the Genesis submission, advised that given distributors would simply pass on the cost, the proposal would not incentivise distributors to improve their power factor, and went on to criticise the Authority's proposal for not ensuring that distribution companies *"replicate the kvar charge in their network prices to preserve the efficiency of the charge"*[205].

9.3.4 The remaining four parties that supported the concept but not the detail of the proposal were CHH, Pioneer, Phillip Wong Too, and Smart Power.

9.3.5 CHH did not support the 0.95 power factor proposing instead that reactive power should be solved on a case by case basis. Pioneer questioned the proposal's reliance on RCPD to generate charges due to inherent problems with RCPD as a measure. Phillip Wong Too suggested that the power factor of 0.95 should only be applied at times of peak demand, advising that rules should be designed to ensure that distributors do not over compensate, particularly during times of low demand as reactive power consumption can actually assist Transpower in controlling system voltages during times of low demand.

9.3.6 Smart Power noted that the proposal provides an effective signal but suggested that the signal could be improved by charging kvar at peaks instead of kW, which would send a price signal allowing customers to make the decision about whether or not to pay or install reactive support. Smart Power also suggests it would be better to *"set the period of the day that the charge will occur in so that they have certainty and can react"*[206].

Assessment of the Authority's dynamic reactive support proposal (Question 22)

9.3.7 15 submitters commented on the Authority's proposal for dynamic reactive support. Six parties supported or broadly supported the Authority's proposal.[207] MEUG and Meridian supported the proposal to align dynamic support charges with interconnection and HVDC charges in general. Nine parties were considered to disagree with the Authority's proposal.[208]

[204] Genesis submission, p. 47

[205] Genesis submission Appendix C, Castalia report , p. 22

[206] Smart Power submission, p. 9

[207] Contact, Meridian, NZ Steel, Pacific Aluminium, Smart Power, MEUG

[208] ENA, Genesis, MRP, Orion, Powerco, PwC, Transpower, Unison, WEL

9.3.8 Distributors' views were communicated through the PwC and ENA submissions and were not supportive of the proposal. ENA submitted that the Authority's proposal to recover dynamic reactive support costs through the interconnection charge was contrary to what was stated in the consultation paper, a change from existing arrangements, as currently charges are currently recovered through System Operator Service Agreements and not the interconnection charge. Powerco cited an error in paragraph 4.5.9 of the consultation paper that described the costs of dynamic reactive support under the current TPM as being recovered via an interconnection charge. Both ENA and PwC advised that they supported the current method rather than the proposed method.

9.3.9 Transpower advised that it could not recover dynamic reactive support through SPD charges as SPD would not reveal the impact of reactive power devices and also suggested the current method is retained.

9.3.10 Meridian supported the Authority's proposal stating that identification of exacerbators is difficult. It notes however that *"the identification of network capacity benefits driven by dynamic reactive support is non-trivial"*[209].

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[209] Meridian submission, p. 55

10. Proposal: beneficiaries-pay SPD model (Questions 23 to 25)

10.1 Overview: beneficiaries-pay SPD model

10.1.1 HVDC and interconnection charges are the most contentious components of the TPM. The Authority considered that parties generally accept charges where they can see the link between the charges they pay, the cost of service to them and the benefits they receive.

10.1.2 The Authority proposed a beneficiaries-pay approach using the SPD model to identify the beneficiaries of each transmission asset. The SPD model uses half hourly prices to calculate beneficiaries by comparing actual prices with modelled prices, based on a counterfactual whereby the asset from which beneficiaries are being estimated did not exist.

10.1.3 The Authority considered that the SPD model:

(a) promotes efficient transmission investment

(b) promotes efficient investment by generation and load

(c) promotes allocative efficiency

(d) promotes durability.

10.1.4 The Authority proposed to apply the SPD model to post May 2004 assets, Pole 2, and only for assets with a value of greater than $2 million. Billing would be calculated ex post on a monthly basis using half hourly time periods from SPD.

10.2 What the Authority asked

The Authority asked questions in relation to:

(a) the SPD model as a beneficiaries-pay approach for recovering HVDC and interconnection costs **(Questions 23 and 24)** and whether there are any viable beneficiaries-pay alternatives **(Question 25)**.

(b) note the proposed SPD model included the following components:

(i) half hourly calculation of benefits against a counterfactual where the asset in question did not exist

(ii) monthly ex post billing cycle

(iii) half hourly cap on charges

(iv) inclusion of HVDC assets and HVAC assets of a value greater than $2million and which were commissioned post May 2004, plus pole 2

(v) Unserved energy variable of $3000/MWh

(vi) gross injection at the GXP.

10.3 Feedback: beneficiaries-pay SPD model

Assessment of support for a beneficiaries-pay approach

10.3.1 35 submitters commented on whether a beneficiaries-pay approach is the optimal approach from recovering HVDC and interconnection costs. 16[210] of these submitters either supported or partially supported beneficiaries-pay as the optimal solution while 19 submitters did not.

Beneficiaries-pay is appropriate

10.3.2 Buller Electricity Electricity submitted that it supported the Authority's "*preference for a beneficiaries-pay approach to the allocation of interconnection costs*" but questioned whether generators are beneficiaries.[211] NZCID similarly supported "*in principle the allocation of costs to those who use and benefit from investments*".[212] Transpower submitted that it did not have "*any objection to aligning charges with beneficiaries in a workable and durable way*".[213]

Further consideration of beneficiaries-pay necessary

10.3.3 A number of parties considered that further consideration of the beneficiaries-pay approach was necessary.

10.3.4 Fonterra submitted that the proposal to use a beneficiaries-pay model requires further consideration. Fonterra advised that *"other NZ infrastructure, such as the transportation network (roads, bridges, etc), utilise a user pays system. It would be difficult to apply a beneficiaries-pay model due to the discrepancy and difficulty in assigning the benefit that different users would gain from the transportation network. For example, there is a difference in benefit that a truck driving on the road to deliver goods receives, compared to the benefit that a person in an ambulance driving on the road receives. Both users get charged on a road user basis, not on the individual benefit they derive from driving on the road"*.[214]

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210 Support or partial support for beneficiaries-pay was considered to come from: Transpower, MEUG, Pacific Aluminium, Meridian, Orion, AECT, Buller, Business NZ, CHH, Contact, Genesis, NZCID, NZWEA, Northpower, Nova, Unison

211 Buller Electricity submission, p. 6

212 NZCID submission, p. 1

213 Transpower submission p. 7

214 Fonterra submission, p. 2

10.3.5 The NZWEA suggested that the *"beneficiaries pays model at a theoretical level seems equitable but whether it can be made to work in practice to the level proposed in the TPM is questionable"*.[215]

10.3.6 Business NZ advised that it doesn't necessarily disagree (with the proposal) but more information required 'the sooner the better' due to impacts of asset sales.[216]

10.3.7 Orion suggested that the Authority further develop *"the idea of beneficiaries-pay, but in a longer term context where it: (a) attempts to establish reasonably enduring and stable cost allocations for interconnection assets, perhaps with regular updates (b) clearly links the grid new-investment decision-making process to the assessment of benefits"*.[217]

Status-quo is the optimal approach

10.3.8 Some parties submitted that the status quo approach was optimal.

10.3.9 NZGA *"favoured a continuation of "postage stamp" pricing for interconnection charges directed to load or distributors as it is currently. NZGA considered that the proposal would "send complex price signals to a generator market that cannot respond in terms of location of new generation, and can only undertake a second order response in terms of offer strategies for existing generation"*.[218]

10.3.10 Unison considered *"the status quo approach to transmission investment and pricing can be characterised as … a mixed model of beneficiaries-pay (connection assets and HVDC charges) and postage stamp (intended to minimise distortions in use of the interconnection assets)"*.[219]

10.3.11 DEUN does *"not accept the argument that "beneficiaries" should pay for use of Transpower interconnection assets. Instead those who we consider to be "exacerbators" should pay for a major part of costs of interconnection assets…thus the existing Regional Coincident Peak Demand pricing is the best approximation for pricing of interconnection assets"*.[220]

Beneficiaries-pay issues

10.3.12 Many submitters considered there were issues with the beneficiaries-pay approach that warranted consideration.

10.3.13 Northpower considered that *"under the proposed "beneficiaries pays" methodology, participants who are deemed to benefit from a new investment*

215 NZ Wind Association, p. 1
216 Business NZ submission, p. 10
217 Orion submission, p. 2
218 NZGA submission, p. 2 and 6
219 Unison submission, p. 6
220 DEUN submission, p. 1

would be required to pay whether they supported the investment, favoured an alternative strategy, or saw no need for the project at all".[221]

10.3.14 Business NZ suggested that *"short-run (beneficiaries-pays) pricing may not be the best way to provide signals for long-run investment decisions."*[222]

10.3.15 Buller Electricity Electricity suggested the Authority reconsider the impact of a beneficiaries-pay regime on generators. According to Buller Electricity, *"if generators are going to be subject to an interconnection charge that reflects their benefit from new transmission investments, then they have an incentive to change their offer prices to minimise the potential transmission cost".* [223] Buller Electricity Electricity considered that the form this could take is unclear.

10.3.16 AECT noted that beneficiaries-pay will only recover around 20% of total revenue with the rest of the cost being spread. AECT submitted that considering the significant cost of implementing a beneficiaries-pay regime, it appears difficult to justify it.[224] AECT also noted that *"consumer's short term price elasticity being likely to be very low"*, suggesting that the signals that a beneficiaries-pay regime might provide, would not be responded to.[225]

10.3.17 While Unison shared *"the Authority's sentiment that it would be desirable that beneficiaries should more specifically pay for transmission investments and that it would be preferable to resolve once and for all the incidence of the HVDC charge, Unison submits that the Authority's proposed solution is likely to create un-intended consequences"*.[226]

10.3.18 PwCPwC and Philip Wong Too[227] considered that the substantial changes to the current TPM will create large wealth transfers, and a perception that New Zealand is *"a risky place to do business*", resulting in a risk premium, at a "*cost to society as a whole"*.

10.3.19 WPI Limited (WPI)[228] considered that the changes would cause a disruption that would last several years. Auckland Airport submitted on a preference for regulatory certainty.[229]

10.3.20 Clearwater Hydro submitted that *"recovering revenue from a fixed infrastructure asset via a dynamic pricing regime seems flawed"*.[230]

Assessment of the SPD model (Questions 23 and 24)

221 Northpower submission, p. 2

222 Business NZ submission, p. 8

223 Buller Electricity submission, p. 14

224 AECT submission, p. 1

225 AECT submission, p. 5

226 Unison submission, p. 4

227 Philip Wong Too submission, p. 4

228 WPI submission, p. 2

229 Auckland Airport submission, p. 1

230 Clearwater Hydro submission, p. 6

10.3.21 45 submitters commented on the viability of the SPD method, while nine submitters did not comment directly on the SPD method. Seven of the commenting submitters partially supported the Authority's proposal while 38 submitters did not support the Authority's proposal.[231]

10.3.22 Submitter responses have been grouped into categories which relate to either components of the SPD model or potential impacts of the model's implementation. The categories are: half hourly calculation of benefits, half hourly cap, monthly ex-post charges, generator inclusion, HVDC inclusion, sunk asset inclusion, threshold inclusion, reliability, benefits and dis-benefits, the unserved energy value, and the counterfactual. The impacts of SPD were also separated considered in sections including: volatility, uncertainty, complexity, gaming opportunities, and increased costs of electricity.

Partial support for SPD

10.3.23 Nova submitted that it concurred with "*the views of other parties that introducing the SPD methodology has a number of disadvantages, but believe that those disadvantages are manageable.*"[232]

10.3.24 SmartPower submitted that the SPD model generally "*seems like a sound way to establish the beneficiaries of the grid*". SmartPower also stated that it seemed "*sound to use the model which is already in place for other purposes and which will be reasonably familiar to market participants plus giving transparency which is good*". However, SmartPower also had concerns with the SPD model. For example, it submitted that the "*SPD method will enable most consumers…to receive signals only in retrospect*".[233]

10.3.25 Business NZ welcomed the efforts made by the Authority in its "*search for a durable resolution*", but wondered whether its "*search for an elegant solution has resulted in over-complication*", and, in particular, it was "*not persuaded that half-hourly transmission charge volatility will aid more efficient electricity use*". Business NZ further commented that "*this is not to say that Business NZ disagrees with the proposal"* but submitted that *"more work on the components and scope of the proposal is required"*.[234] Furthermore, Business NZ submitted that, in terms of a beneficiaries-pay regime, "*the ideal is to establish the charging regime at the commissioning time and not change it subsequently*".

Half-hourly calculation of benefits does not address long-term benefits

10.3.26 Many submitters did not support half hourly transmission charges.

231 Partial support for the SPD method was from MEUG, NZX, Pacific Aluminium, Meridian, Smart Power, Business NZ, and Nova

232 Nova submission, p. 3

233 SmartPower submission, p. 10-11

234 Business NZ submission, p. 8-9

10.3.27 Smart Power considered that the Authority *“should be careful not to be too purist when it comes to pricing”* and that *“clear and consistent signals (were required) so that people can react correctly time and again”*. Smart Power suggested that signalling every half hour is overkill from a consumer’s perspective.[235]

10.3.28 Norske Skog suggested *“the main reason the SPD is so ineffective in charging beneficiaries arises from the Authority’s intention to calculate benefits from every single trading period of the year”*. Norske Skog considered that *“the fundamental reason that transmission investments are built is to meet peak demand”* and thus recommended that TPM should charge according to a small number of peak periods, rather than every half hour.[236]

10.3.29 TrustPower advised that a *“the SPD charge is focused only on gross benefits calculated by the half-hour, not net benefits in the long run”*. TrustPower considered that the model takes no account of benefits any longer than a half hour, and that alternatively, a long-term contracting approach addresses long term benefits by forcing parties to reveal their *“willingness to pay”*.[237]

10.3.30 Business NZ submitted that it was *“not persuaded that half-hourly transmission charge volatility will aid more efficient electricity use or transmission investment decisions”*.[238]

10.3.31 PwC suggested *“smoothing the SPD charge by adopting a longer trading period (eg hourly, monthly, annual) or exploring other, less volatile, alternatives to the SPD beneficiaries pays approach”*.[239]

Half-hourly cap reduces cost recovery potential of SPD

10.3.32 Many submitters including Contact[240], Pacific Aluminium, Vector, and Waipa did not support the half hourly price cap.

10.3.33 Pacific Aluminium submitted that *"the half-hourly price cap is completely arbitrary and unjustified and means the cost of an asset can never be fully recovered in practice, resulting in an unnecessarily large residual”*.[241]

10.3.34 Vector described SPD as a *“beneficiary-lite”* approach, *“which places a half-hourly cap on SPD charges at average transmission cost, on the basis that this is needed to limit —the size of the incentives on participants to act inefficiently”*.[242]

235 Smart Power submission, p. 11
236 Norske Skog submission, p. 12
237 TrustPower submission, p. 20-21
238 Business NZ submission, p. 8-9
239 PwC submission, p.10
240 Contact submission, p. 4
241 Pacific Aluminium submission, p. 3
242 Vector submission, p. 4

10.3.35 Waipa requested the Authority *"examine the signals a capped beneficiary pays model is creating for future investments"* and suggested there should be no cap.[243] Meridian suggested adopting a less volatile charge, by changing the *"time period for benefits capping"* from half-hourly to weekly or monthly.[244]

Monthly ex post charge calculation

10.3.36 Many submitters contended that monthly ex post charges would cause volatile, uncertain charges.

10.3.37 NZ Steel and Buller Electricity Electricity advised that monthly ex post charges would result in an unacceptable level of volatility. AECT commented that currently charges were known one year in advance and the change would cause considerable uncertainty.[245]

10.3.38 TrustPower, supporting an ex ante allocation, submitting that an ex-ante determination is *"consistent with the approach generally followed by private investors, in which revenue streams are determined (and often firmed) prior to the investment reaching financial close"*.[246]

Inclusion of generators in SPD will increase costs to consumers

10.3.39 A number of submitters expressed concerns with generation being included within the SPD benefits calculation.

10.3.40 Pacific Aluminium considered that the *"most critical issue is that the charges to generators must be 'sticky'. That is, they must be as difficult to pass through in short-run offer prices to the wholesale electricity market as possible"*.[247]

10.3.41 Vector noted that currently, *"wholesale electricity prices South Island generators receive are generally capped by North Island generation, so the ability of South Island generators to pass on the HVDC charges through higher prices is significantly limited"*.[248] Vector and PwC[249] indicated that extending this charge to all generators will result in a higher level of charges being passed through by generators.

10.3.42 MainPower advised *"introducing transmission charges at the generator level simply adds another step in the chain of payments in which the costs will ultimately be borne by the consumer"*. MainPower predicted that existing

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243 Waipa submission, p. 5

244 Meridian submission, p. 8

245 AECT submission, p. 4

246 TrustPower submission, p. 4

247 Pacific Aluminium submission, P. 3

248 Vector submission, p. 17

249 PwC submission, p. 3

generators would increase wholesale prices to recover their additional costs.[250]

Changes to HVDC cost allocation

10.3.43 Submitters were divided in their view over whether HVDC charges should be incorporated in the SPD model and whether HVDC charges should be changed at all. While a number of gentailers were of the view that changes were necessary, many consumers and a number of distributors felt status quo charges were preferable as South Island generators benefit considerably from HVDC and the charges are well known. Transpower agreed there was an issue with HVDC charge allocations but was not convinced that it was material enough to warrant changes to the status quo.

10.3.44 Meridian supported consistent treatment of HVDC and HVAC assets on the basis that *"there is no evidence demonstrating that HVDC and HVAC assets perform different functions, deliver different benefits, or are different in any way that is relevant to transmission pricing"* and that *"different treatment results in considerable inefficiencies"*.[251] Meridian agreed that parties should not pay any more than their private benefit.

10.3.45 Vector submitted in favour of South Island generators continuing to pay the full cost of the HVDC link. Vector advised that the *"current HVDC charges provide a pragmatic form of partial locational pricing"*. Vector also considers that the benefit South Island generators receive from the HVDC (including Pole 2 and 3 combined) exceeds the costs. Vector noted that *"the current HVDC charges also recognise that the HVDC link (and upgrade) is required because of the excess of generation relative to electricity demand in the South Island i.e. South Island generators are both beneficiaries and exacerbators in relation to the HVDC link"*.[252]

10.3.46 Vector submitted that the Authority (and TPAG) should have taken a *"long-run perspective and determined what would result in lowest delivered (generation plus transmission) costs"*. Vector advised that this would require determination of *"(i) the LRMC of electricity transmission from the South to the North Island; and (ii) that the current HVDC charges exceed LRMC"*.[253]

10.3.47 Transpower acknowledged that the current HVDC charge has some problems, and that the Authority has proposed an innovative potential solution. However, *"the Authority has not demonstrated that there are material problems that would warrant a change to interconnection charges"*.[254] Transpower advised that the following points should be considered:

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[250] MainPower submission, p. 3

[251] Meridian submission, p. 5

[252] Vector submission, p. 4-5

[253] Vector submission, p. 5

[254] Transpower submission, p. 2

(a) any ‘unbundling’ of the collective HVDC assets (e.g. charging for Pole 2 and Pole 3 separately) will require difficult allocation decisions regarding common costs

(b) a decision would be required on how to allocate the ‘legacy’ economic value account balance (currently around $100 million)

(c) a one-off (or, at least, infrequently recurring) assessment of beneficiaries would be less costly and less problematic.[255]

10.3.48 Pacific Aluminium submitted that Transpower’s economic value accounts “*reveal that the current balance of HVAC is $52.1m, which represents an accumulated overpayment by consumers and must be returned to consumers only. However the HVDC account is $104.1m in deficit which represents an accumulated undercharging of SI generators and must be recovered in future from them alone and not from consumers*”. [256]

10.3.49 Contact noted that, *“while South Island generators have always paid for the HVDC, this was only ever designed as a temporary measure and was a compromise that was agreed while a more robust pricing policy was developed”*. According to Contact, *“South Island generators have never agreed they alone should be liable for the HVDC link and it has always been foreseeable to market participants that at some stage they were likely to become liable for a share of that cost”*.[257]

10.3.50 The ENA submitted that it *“does not consider the case has been made that it is in the long-term interests of consumers to bundle the HVDC charge with the IC I(interconnection Charge) charge”*.[258]

10.3.51 Pulse commented that HVDC (cost allocation) appears to be the only issue (in the TPM) that requires fixing.[259]

10.3.52 Tuaropaki advised that the proposal involves a significant departure from the existing TPM *“ will invariably create winners and losers”* and that *“the re-allocation of HVDC charges to North Island generators will increase their expected transmission costs (all other things being equal)”*.[260]

10.3.53 Pacific Aluminium suggested that a market-based approach, such as capacity rights, could be an appropriate approach to allocate costs for Pole 2 and 3 assets of the HVDC *“as the computational and market requirements look only moderately more complex than the SPD method itself and the developing FTR market”*. Pacific Aluminium also submitted *“there is no efficiency gain to be had from including the costs of the Pole 2 HVDC assets*

255 Transpower submission, p. 3

256 Pacific Aluminium submission p.4

257 Contact submission, p. 15

258 ENA submission, p. 2

259 Pulse submission, p. 2

260 Tuaropaki submission, p. 2-3

in the SPD method as the Authority's own analysis has shown that the aggregate private benefits to SI generators exceed their aggregate costs and the alleged inefficiencies of the current allocation are arguably not material".[261]

Reallocation of costs for sunk assets

10.3.54 Vector advised the Authority to *"make an explicit judgement as to whether the focus of the TPM should be on recovery of sunk costs in a way that minimises distortions to nodal pricing and transmission network use (static efficiency) or on long-run (dynamically efficient) signalling of future transmission capacity costs e.g. locational-pricing"*.[262]

10.3.55 Contact submitted that the proposal discouraged the use of a network whose costs are sunk. Contact advised that regardless of whether the benefits stack up, *"the decisions have been made and these costs cannot be avoided, they are sunk costs"*.[263]

10.3.56 Meridian argued that *"there is nothing retrospective about the Authority's proposal.If implemented the TPM would only apply to prices going forward"* and *"a rational investor would not assume that the rules relating to its investment will never change. The key is that the changes in the rules of the game are principled"*.[264]

10.3.57 MEUG submitted that it *"did not accept that problems with the current TPM for allocating sunk costs are material enough to justify significant changes (chapter 4) where the efficiency gains from re-arranging sunk costs are not obvious"*.[265]

10.3.58 Northpower considered the *"Authority's proposal to apply "beneficiaries pay" to new grid investments approved since 2004 is effectively retrospective legislation"*.[266] Business NZ also noted *"retrospective application of the new approach is hard to justify on the grounds of good regulatory practise"*.[267]

10.3.59 Unison submitted that since *"investment is largely sunk, charges should be as least distortionary as possible"*.[268]

10.3.60 Vector advised that the proposal to apply the SPD model to post 2004 assets would dis-incentivise use of post 2004 assets.[269]

261 Pacific Aluminium submission, p. 3

262 Vector submission, p. 31

263 Contact submission, p. 8

264 Meridian submission, p.18

265 MEUG submission, p. 2

266 Northpower submission, p. 2

267 Business NZ submission, p.9

268 Unison submission, p. 15

269 Vector submission, p. 42

10.3.61 Auckland Council suggested that *"introducing locational signals for sunk costs would have a limited positive influence on dynamic efficiency; however the constant reallocation of transmission charges for sunk assets could incentivise market participants to act in ways that compromise static efficiency"*.[270]

10.3.62 ACC advised that the *"implications of back-dating the proposal to 2004"* increased the scope for *"disputes and changed price setting 'surprises"*.[271]

10.3.63 ACC also advised that a US Court of Appeal cautioned against the re-pricing of past investments.[272]

10.3.64 Ringa Matau submitted that it considered *"the impacts of reallocating sunk costs are particularly significant for inflexible generators such as geothermal who are unable to pass through transmission charges"*.[273]

10.3.65 Clearwater and Alinta considered that there was little value in providing strong incentives when the majority of costs are sunk.

Threshold too low for inclusion of current and future assets in the SPD model

10.3.66 Many submitters were of the view that the $2 million threshold was too low and that there were too many assets in the SPD model. Submitters contended that the SPD model could be improved by increasing the value threshold and including only a small number of assets in the SPD model.

10.3.67 Philip Wong Too advised that the $2 million threshold included too many assets. Contact suggested that the volatility of the charge would reduce by only including assets of a value greater than $100 million.[274]

10.3.68 Meridian proposed that for simplicity, the SPD should include only five current assets and going forward, incorporate only assets worth more than $50 million (or alternatively $100 million).[275]

SPD does not adequately consider reliability

10.3.69 Some submitters suggested that the value of reliability is not adequately considered by the SPD model.

10.3.70 EPOC suggested that question of who is paying for the reliability benefits of additional grid assets is important.[276]

10.3.71 Waipa considered that the TPM fails to recognise 'quality of service'.[277]

270 Auckland Council submission, p. 1

271 ACC submission, p. 2

272 ACC submission, p. 4

273 Ringa Matau submission, p. 2

274 Contact submission, p. 4

275 Meridian submission, p. 8

276 EPOC submission, p. 7

10.3.72 Nova noted that the Authority *"has not recognised in its analysis that the benefits of reliability of supply are not valued equally by generators and consumers. The SPD methodology presumes that both consumers and generators have the same interest in the reliability and security of supply of the grid"*.[278]

10.3.73 Nova considered that the SPD was valid for collecting up to 25% of interconnection costs, in relation to power flows across the grid, while 75% is unutilised, and *"should be paid for by consumers"* who value and benefit from reliability.[279]

10.3.74 Genesis noted that the proposal would *"discourage investment in peaking and accelerate retirement of existing peaking or firming generation"*.[280]

SPD does not accurately calculate benefits and dis-benefits

10.3.75 Some parties submitted that the SPD model does not accurately calculate benefits.

10.3.76 Norske Skog advised that the proposal did not consider the dis-benefits of SPD.[281]

10.3.77 TrustPower pointed out that *"if a new transmission asset makes a party worse off for 95% of trading periods, but better off for 5% of the time, the party will still face charges for those 5% of trading periods, despite having no long-run willingness to pay for the asset"*. TrustPower considered that, "*the willingness of NI generators to pay for the HVDC link would clearly be negative, as they would prefer it did not exist.*" [282]

10.3.78 Powerco submitted that the *"claim that the SPD method is a "beneficiary pays" allocation method is only partly true. Solving SPD with and without a particular asset will reveal the "spot benefit" of a particular asset during a given trading period. However, if the asset concerned were not actually present, the behaviour of generators and, to some degree, load would be different because of that fact and, consequently, the prices produced by SPD would also be different"* (also refer the *"counterfactual"* section of this document).[283]

10.3.79 Powerco also noted that a party may *"benefit in the form of an insurance or option. "And hence unserved load avoided" even though it is* not seen as a benefit by the SPD.[284]

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277 Waipa submission, p. 2

278 Nova submission, p. 1

279 Nova submission, p. 3

280 Genesis submission, p. 7

281 Norske Skog submission, p. 13

282 TrustPower submission, p. 21

283 Powerco submission, p. 13

284 Powerco submission, p. 13

10.3.80 According to Orion, if it has *"interpreted para 5.6.15 correctly, the benefits associated with the avoided supply interruptions that are not captured by the SPD calculation are "non-monetary", whereas those associated with notional wholesale market effects, as depicted in Figure 8, are "monetary""*.[285]

10.3.81 Orion also noted that SPD solves are incorrect as supply curves are not curved but stepped.[286]

Unserved energy value either too high or too low

10.3.82 Submissions were divided on an appropriate value for unserved energy with some submitters preferring a higher value to reduce market distortions while those preferring a lower value submitted that $3,000/MWh was based on a short term view of a counterfactual.

10.3.83 Energy Link advised that the *"higher the VoLL assumed when calculating the SPD charges, the higher the potential share of the charges that would be paid by direct connect consumers and by retailers, relative to generators"*. Energy Link *"expects the choice of VoLL would cause significant debate, lobbying, and ultimately disputes that could end up in court"*.[287]

10.3.84 Pacific Aluminium[288] and Fonterra recommended that the unserved energy value is less than $3000/MWh that the counterfactual used in the SPD model is inappropriate. Pacific Aluminium and Fonterra explained that the proposed unserved energy value of $3000/MWh was based on diesel generation costs but that this was a short term solution and in the long run a cheaper solution than a diesel generator would be used.

10.3.85 Norske Skog also commented that the price of $3000/Mwh was very high.

Contact submitted for a higher unserved energy value, considering that this would reduce complexity and market distortions. Contact suggested $20,000/MWh as an appropriate unserved energy value.[289]

Counterfactual is wrong or uncertain

10.3.86 Some submitters commented that the counterfactual should be clearly defined and reflect a long term perspective.

10.3.87 Energy Link suggested that the proposal lacked definition of how a counterfactual would be constructed.[290]

10.3.88 Vector advised that *"any measurement of private benefits should be based on a counterfactual where the transmission asset never existed (long-term*

285 Orion submission, p. 3-4

286 Orion submission, p. 5

287 Energy Link submission, p. 3

288 Pacific Aluminium submission, p. 3

289 Contact submission, p. 4

290 Energy Link submission, p. 3

perspective) rather than the immediate impact of removing an asset (short-term perspective)".[291]

10.3.89 EPOC submitted that *"without explicit demand-side bidding it is likely that consumer benefits will be overstated, as historical fixed demands will be used when, in fact, without the grid asset demand may have been very different"*.[292]

Volatile charges

10.3.90 Many submitters considered the proposed SPD charge would significantly increase the volatility of transmission charges.

10.3.91 Alinta advised that the SPD model was *"particularly complex and creates significant uncertainty"*.[293] This view was shared by AECT, Auckland Council, Philip Wong Too, Ventus, Tuaropaki (Cognitus), Powerco, Ringa Matau, Meridian, Pioneer, Energy for Industy, MainPower, Energy link, Genesis, NZX, Orion, and Nova. WPI noted that the SPD lacked transparency.[294]

10.3.92 WEL submitted that ex post pricing was too volatile for its Default (DPP) Price Path regulation.[295]

10.3.93 Buller Electricity Electricity submitted that the additional volatility would result in higher prudential requirements.[296] Pulse suggested the Authority evaluate the impact of ex post half hourly prices on prudentials.[297] A number of submitters considered that this would be a barrier to new market entrants and thus adversely impact retail competition.

10.3.94 Simply Electricity submitted that *"the value of the hedge market will be undermined, as it will be less useful for both pricing and managing risk"*. Simply Electricity advised that *"inter-network volatility in energy prices that a large - diversified retailer may be able to manage but* pose a *significant risk to smaller retailers operating in a limited number of networks"*. [298]

10.3.95 EMS advised that the SPD method represented *"another price risk on top of that inherent in the nodal prices"*[299] while there is no hedge product available to hedge against this added risk.

291 Vector submission, p. 4
292 EPOC submission, p.7
293 Alinta submission, p. 1
294 WPI submission, p. 2
295 WEL submission, p. 1
296 Buller Electricity submission, p. 11
297 Pulse submission, p. 1
298 Simply Electricity submission, p. 1
299 EMS submission, p. 1

10.3.96 Tuaropaki submitted that the SPD-based beneficiaries-pay charge will be tied to volatile wholesale electricity prices, which is not a good hedge for generators if they are not earning spot revenue.[300]

Complex charges

10.3.97 Many submitters considered the proposed SPD charge would significantly increase the complexity of transmission charges.

10.3.98 Genesis submitted that the increased complexity inherent in the proposal *"carries with it a very real risk of creating information asymmetry between two distinct classes of market participant…those who can afford to understand the Proposed TPM". 'Those who do not." "It is likely that the latter group will pay a proportionally greater share of transmission costs and suffer a market disadvantage. The volatility and complexity of the Proposed TPM, especially with so many design factors as yet unknown, increases the risk of unforeseeable negative consequence"*.[301]

10.3.99 Auckland Council described the proposal as a *"highly complex theoretical approach."*[302] Phillip Wong Too advised that it would likely cause a risk premium.

10.3.100 Simply Energy advised that there would be a requirement to upgrade billing systems to handle *"retrospective wash-ups to consumer invoices"*.[303]

Muting response to peaks

10.3.101 Some submitters suggested that the proposed methodology would weaken incentives for effective response to peaks.

10.3.102 ADHB submitted that *"the proposed new methodology will reduce the weighting given to these peaks and that the weighting may also change from month to month.Such changes would reduce the likelihood that ADHB would respond in an efficient manner. Firstly it will be less worthwhile to respond to peaks in general as the potential savings would be significantly reduced. Secondly it will be more difficult to predict which peaks to respond to, as the weighting of any particular peak in the pricing methodology will only be known post-event"*.[304]

10.3.103 Business NZ advised that *"evidence that market-based price signals are able to be responded to in real time will be important to this"*.[305]

10.3.104 Smart Power expressed concerns that most consumers will only receive signals in retrospect.[306]

[300] Tuaropaki submission, p. 3

[301] Genesis submission, p. 5

[302] Auckland city council submission, p. 2

[303] Simply Energy submission, p. 2

[304] ADHB submission, p. 1

[305] Business NZ submission, p. 10

Creation of gaming opportunities and generator peak avoidance

10.3.105 Some submitters suggested that the SPD model could create gaming opportunities and that together with the proposed residual charges could incentivise generators to avoid peaks.

10.3.106 Genesis advised that *"the SPD method and the RCPI component of the residual method both have the potential to alter generator spot market offer behaviour away from optimally efficient spot market outcomes. Generators will be incentivised to manage their transmission costs. This may be by seeking to "pass through" the maximum volatility in the offer price, or by adjusting offer strategies to minimise exposure to transmission allocations (thus shifting the burden to other parties)"*.[307]

Unison questioned why the Authority considers it wants generators to avoid peaks.[308] Unison also advised that the *"SPD-based allocation and RCPI charge would further distort nodal prices and create incentives to avoid the use of the sunk transmission network"*.[309]

Increase in consumer prices

10.3.107 A number of submitters contended that the proposal would impact negatively on consumer prices.

10.3.108 Tuaropaki submitted that the proposal would increase both transmission costs and variability of transmission costs.[310]

10.3.109 Genesis considered that since there is no hedging option for the proposed transmission cost risks, this will result in a risk premium.[311]

10.3.110 Unison submitted that the proposal would:

- *(a)* *"distort prices in the spot electricity market"*
- *(b)* *"increase risks in the spot electricity market"*
- *(c)* *"increase administration and transaction costs"*
- *(d)* *"impact on retail and wholesale competition"*
- (e) *"increase perceptions of regulatory risk"*.[312]

Alternative beneficiaries-pay charging options (Question 25)

10.3.111 23 submitters suggested alternative charge options to the SPD method.

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306 Smart Power submission, p. 11

307 Genesis submission, p. 7

308 Unison submission, p. 14

309 Unison submission, p. 8

310 Tuaropaki submission, p. 52

311 Genesis submission, p. 5

312 Unison submission, p. 3-4

SPD alternatives

10.3.112 Some submitters suggested alterations to the SPD method to make it more workable.

10.3.113 Pacific Aluminium suggested that the SPD method may be workable for *"recent and future investments in HVAC* interconnection assets*"*.[313]

10.3.114 PwC suggested *"smoothing the SPD charge by adopting a longer trading period (eg hourly, monthly, annual)" or "exploring other, less volatile, alternatives to the SPD beneficiaries pays approach"*.[314]

10.3.115 Meridian and Energy Link[315] suggested that the SPD be *"forward-looking"*.

10.3.116 Meridian proposed a modified SPD based beneficiaries-pay regime consisting of the following:

(a) for simplicity, incorporate five current assets[316] and going forward, incorporate only assets worth more than $50 million (or alternatively $100 million)

(b) for certainty, employ annual ex ante charges

(c) to address volatility, change *"time period for benefits capping"* from half-hourly to weekly or monthly.[317]

10.3.117 Genesis recommended the Authority investigate a range of capping options, include all assets, consider calculating benefits on a regional basis, assess a range of counterfactuals, and consider dis-benefits.[318]

10.3.118 Nova recommended that the *"portion of the grid carrying actual load (determined from utilisation factor) can be charged on the basis of the SPD calculations as it reflects the beneficiaries of those power flows"* and the *"the portion of the grid providing N-1 security of supply should be paid for by consumers"*, with the *"remaining portion, which represents allowances for demand growth, size of upgrades, etc. can be socialised on a targeted basis"*.[319]

10.3.119 DEUN suggested the Authority *"spend a year assessing SPD charges"*.[320]

Other beneficiaries-pay alternatives

10.3.120 Some submitters suggested alternative beneficiaries-pay options.

313 Pacific Aluminium submission, p. 2

314 PwC submission, p.10

315 Energy Link submission, p. 14

316 Pole 2, Pole 3, NIGUP, NAaN, Wairakei Ring

317 Meridian submission, p. 8

318 Genesis submission, p. 48

319 Nova submission, p. 4

320 DEUN submission, p. 12

10.3.121 Transpower suggested that a one-off (or, at least, infrequently recurring) assessment of beneficiaries would be less costly and less problematic than more frequent assessments.[321]

10.3.122 Transpower submitted that the *"current interconnection charge delivers stability and simplicity and is not inconsistent with a beneficiary pays philosophy"*. Transpower encourages further work on *"determining the best approach, delivering a stable, simple and forecastable charge"*.[322] Fonterra suggested flow tracing as a methodology that identifies users as a proxy for beneficiaries pays. Fonterra recommended the Authority *"expand the deep sunk asset allocation"* submitting that this ensures that costs are known in advance, and there is no risk premium attached. Fonterra also suggested a forecast model approach in which, prior to transmission asset investments being made, costs are allocated to the beneficiaries using a commercial model and the *"beneficiaries agree to pay at the time that the investment decision is made"*.[323]

10.3.123 Clearwater submitted that *"flow tracing appears to offer the best alternative to recover HVDC cost compared to the status quo as it can provide inter year price certainty."* *"Limits could be placed on inter year variability to provide stability"*.[324]

10.3.124 AECT recommended that the Authority confine beneficiaries-pay to future investments.[325] CHH similarly advised that there should be separate regimes for sunk assets and future investment in assets.[326]

Non-beneficiaries-pay alternatives

10.3.125 Some submitters recommended the Authority investigate non- beneficiaries-pay alternatives.

10.3.126 Pacific Aluminium advised that a market-based approach, such as capacity rights, may be workable for the Pole 2 and 3 assets of the HVDC *"as the computational and market requirements look only moderately more complex than the SPD method itself and the developing FTR market"*.[327]

10.3.127 Clearwater suggested that the Authority *"listen to the industry"* and if there is general acceptance that HVDC should be recovered across the entire market, then *"recover interconnection and HVDC via RCPD charges"*. According to Clearwater, RCPD *"sends the right signals, are easy to understand, regions can be sized to produce the right result, the costs are*

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321 Transpower submission, p. 3

322 Transpower submission, p. 8

323 Fonterra submission, p. 3

324 Clearwater submission, p.11

325 AECT submission, p. 6

326 CHH submission, p.13

327 Pacific Aluminium submission, p. 3

manageable and a long term reduction in peaks generally will be good for the industry in terms of future investment".[328]

10.3.128 Powerco recommended that *"if the Authority's prime objective is efficiency, it should roll the HVDC charge into the interconnection charge and recover the total costs using the current allocation method, as recommended by the TPAG"*.[329]

10.3.129 ACC noted that the majority view of the Transmission Pricing Advisory Group process that concluded in 2011 was that the *"cost associated with the HVDC should be transitioned over a 10-year lead-in period so that wealth transfer impacts were reduced and the market could dynamically reset incrementally over that time frame"*.[330]

10.3.130 DEUN supported a simple approach as used by Orion Networks, intended to *"provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation"* of assets.[331]

10.3.131 DEUN also recommended *"status quo charges (for) South Island generators alone for the use of the Cook Strait link. This gives incentive for future generation investment to be in the north, closer to the load growth." "DEUN therefore supports the retention of the status quo for HVDC pricing, on the basis of simplicity, predictability, and efficiency of pricing incentive"*.[332]

10.3.132 MRP recommended that the Authority focus on resolving the HVDC issue, starting with a more robust assessment of the TPAG recommendation.[333]

10.3.133 Vector submitted that "*full locational-pricing would best satisfy the Authority's draft decision-making framework*".[334]

Other alternatives

10.3.134 Some submitters made general comments in relation to alternatives or alterations.

10.3.135 NZCID recommended more gradual change to the TPM than that of the current proposal.[335]

10.3.136 NZ Steel submitted that assets that were built but are not required should be written down, as would occur in a competitive market.[336]

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328 Clearwater submission, p. 6
329 Powerco submission, p. 15
330 ACC submission, p. 4
331 DEUN submission, p. 5
332 DEUN submission, p. 5
333 MRP submission, p. 92
334 Vector submission, p. 28
335 NZCID submission, p. 2
336 NZ Steel submission, p.14

10.3.137 Kiwi Rail requested that the Authority consider *"traction systems"* and price certainty when developing the TPM. Kiwi Rail noted that traction systems, which accounts for 60% of Kiwi Rail's (90GWh to 120GWh) annual electricity usage, have *"continuing variable load characteristics"*.[337]

10.3.138 WEL recommended that the Authority ensure that *"transmission charges continue to be set and fixed by Transpower by the November before the forthcoming regulatory year commencing 1 April"*.[338]

10.3.139 Fonterra recommended that the Commerce Commission investment approval process be changed to include voting rights for parties identified as beneficiaries.[339]

10.3.140 MRP suggested that a TPM proposal should:

(a) result from sound problem definition analysis

(b) be properly scoped and evaluated (consistent with best practice cost allocation and within an accepted and robust cost benefit framework with the results verified independently)

(c) be implemented prospectively with an appropriate transition to avoid significant wealth transfer impacts, reduce the impact of regulatory risk, enable the dynamic wholesale market to adjust over time to the new framework without unnecessary distortions

(d) be understandable and transparent to participants and the public

(e) resolve the jurisdictional overlap with the Commerce Commission

(f) appropriately and robustly reflect the Authority's statutory objectives.[340]

10.3.141 Many submitters, including Buller Electricity[341], Energy3[342] and Pioneer[343] requested that the Authority review the impacts of the TPM proposal on distributed generation.

10.3.142 Norske Skog recommended that new SI generators should not have to pay any HVDC charges, given that *"this overcomes any real or perceived investment efficiency"*.[344]

337 Kiwi Rail submission, p. 1
338 WEL submission, p. 1
339 Fonterra submission, p. 7
340 MRP submission, p. 92
341 Buller Electricity submission, p. 12
342 Energy3 submission, p. 4
343 Pioneer submission, p.12
344 Norske Skog submission, p. 9

11. Proposal: residual charges (Questions 26 to 30)

11.1 Overview: residual charges

11.1.1 The Authority considered that the beneficiaries-pay charge may not recover the full costs of a grid investment to which it is applied, in particular for those investments that are made for the purposes of meeting grid reliability standards.

11.1.2 The Authority considered that an efficient residual charge is one that:

(a) minimises distortions in use of the transmission grid resulting from the imposition of the residual charge

(b) ensures the costs of providing transmission investments approved under the relevant regulatory regime are fully recovered (as required by law) and so future investment is not stifled by the concerns of investors in the grid that they will not recover the costs of approved investment.

11.1.3 The residual charge proposed by the Authority:

(a) would be applied equally to generation as well as load

(b) should in principle be applied to electricity retailers as well as direct connect customers

(c) should, to the extent possible, be incentive neutral if other charges are introduced that provide incentives for more efficient investment.

11.1.4 The Authority proposed that the residual charge would apply to distributors but distributors would have the ability to opt-out of the charge except to the extent that they benefit from offering interruptible load, and subject to first consulting with retailers operating on their network.

11.2 What the Authority asked

11.2.1 the residual model for recovering the balancing of HVDC and interconnection costs from generators, direct –connect customers, distributors, and retailers and the portions recovered from each **(Question 26)** and whether submitters supported the proposal to allow distributors to opt out of residual charges **(Question 27)**

11.2.2 whether the residual proposal complements the SPD model **(Question 28)**

11.2.3 whether the charges minimise distortion in use of the transmission grid **(Question 29(a))**

11.2.4 whether the charges will facilitate full cost recovery for Transpower **(Question 29(b))**

11.2.5 whether the residual proposal encourages the efficient avoidance of peaks **(Question 30)**

11.3 Feedback: residual charges

Proposal to apply the residual charge to generators, direct-connect major users, distributors, and retailers (Question 26)

11.3.1 34 submitters commented in the application of the residual charge to generators. Out of those submitters commenting, 27 submitters did not support the proposal while seven submitters[345] either supported or partially supported the proposal.

11.3.2 The main themes emerging from question 26 were that generators should either have a lesser portion of allocation or no allocation of the residual charge, and that there was little appetite for the distributor opt-out clause. Submitter comments are grouped into subheadings below.

RCPI based generator charges appropriate

11.3.3 NZX submitted that the residual charge should be imposed on both generation and consumers *"given that both parties benefit from the transmission grid"*.[346]

11.3.4 NZX suggested that another possibility may be to *"allocate the residual charge to generators and retailers/distributors according to their share of the previous year's SPD charge"*. According to NZX, this would *"enhance alignment between the SPD and residual charge and minimise over-charging of beneficiaries"*.[347]

11.3.5 ENA supported "*in principle the inclusion of an RCPD and possibly an RCPI charge (depending on its design)*." ENA advised that the *"objectives for these charges as part of the overall TPM need to be clarified in order to determine how best to structure these charges and the most appropriate counterparties for them"*.[348]

11.3.6 Vector supported generators contributing to interconnection costs as it broadened the tax base and reduced distributor's role as intermediaries for transmission services. Vector also contended that this would reduce distributor interference with transmission pricing signals. Vector suggested that since generators were less likely to be able to pass through RCPI charges than MWh charges, RCPI charges would better meet the Authority's criteria.[349]

345 Powerco, Vector, ENA, Pacific Aluminium, Meridian, Northpower, and NZX

346 NZX submission, p. 8

347 NZX submission, p. 9

348 ENA submission, p. 2

349 Vector submission, p. 44

11.3.7 Northpower submitted that it has strongly advocated, through a series of consultations, that generators should pay all, or at least 50%, of the costs of the interconnected grid (instead of just the HVDC). Northpower reasoned that *“this would be consistent with the ‘cost of getting the goods to market’ concept”*. According to Northower *“at present, subject to obtaining RMA approvals, generators can set up anywhere in New Zealand, connect to the grid, and only pay for the relevant local connection assets. The Distributors and Direct-connects pay for the entire cost of the interconnected grid and any augmentations, even if those augmentations are required to enable dispatch of new generation”*.[350]

11.3.8 Meridian supports a residual charge because it is least distortionary, is required to recover revenue, spread the cost far and wide, encourages broader oversight, and promotes efficient grid investment.[351]

11.3.9 Nova advised that it had *“serious concerns over the value impact of a RCPI charge and its effect on wholesale electricity prices”*. According to Nova, *“there is no evidence that the proposed RCPI charge will provide benefits in terms of transmission investment”* and *“irrespective of whether the peaks are applied across the year or to a few peaks only, that the RCPI method creates a large value shift from consumers and peaking stations to base load generation”*.[352]

11.3.10 Despite the above objections, Nova suggested that RCPI charges on South Island Generators were one of three suggested ways to recover the balance of interconnection charges.

Charges should be 100% to load and 0% to generators

11.3.11 Unison advised that *“end consumers have relatively inelastic demand and therefore the likely dead-weight losses from levying transmission charges on consumers is likely to be low”*.[353]

11.3.12 Unison added that *“distributors can re-bundle charges into reasonably efficient end-user tariffs”*.[354]

11.3.13 TrustPower submitted that *“nodal pricing best accounts for transmission constraints in exporting regions. Therefore there is no need for an RCPI charge”*.[355]

11.3.14 TrustPower noted Redpoint’s analysis *“allocation to load avoids over-recovery and is consistent with international practice.” “avoids distortions in grid use” and “ avoids risk of increased costs for generators”*.[356]

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350 Northpower submission, p. 3

351 Meridian submission, p. 19

352 Nova submission, p. 10

353 Unison submission, p. 15

354 Unison submission, p.15

355 TrustPower submission, p. 39

Avoidance of peaks

11.3.15 Many submitters that disagreed with the inclusion of RCPI in residual charge argued that RCPI would create generator peak avoidance.

11.3.16 Unison questioned that since *"it is loads that drive peaks with generation responding to meet the demand, it is not clear why the Authority considers it wants generators to avoid peaks"*.[357]

11.3.17 MRP considered that *"any residual charge should be allocated entirely under the existing RCPD mechanism"* as *"developing an RCPI framework to encourage efficient peak avoidance net of wholesale market distortions is likely to be problematic"*.[358] Smart Power noted advantages in the Authority's proposal around investment signals for new generation. However Smart Power had concerns around possible dis-incentives to generate at times of peak demand.[359]

Energy Link also submitted on potential for generators to avoid generating at peak demand to avoid RCPI costs. Energy Link also advised that *"in the short run, a number of factors could influence offer behaviour so it is difficult to predict exactly how offers would change but in the long run we would expect the total cost of transmission (the $7/MWh) to be added to average wholesale spot prices"*.[360]

Generator ability to pass through RCPI and include a risk premium

11.3.18 Many submitters that disagreed with the inclusion of RCPI in residual argued that RCPI charges would be passed though by generators and place upward pressure on consumer prices.

11.3.19 Genesis submitted that the *"SPD method and the RCPI component of the residual method both have the potential to alter generator spot market offer behaviour away from optimally efficient spot market outcomes"*. Genesis consider that generators *"will be incentivised to manage their transmission costs"* which could be achieved by either passing through *"the maximum volatility in the offer price, or by adjusting offer strategies to minimise exposure to transmission allocations (thus shifting the burden to other parties)"*.[361]

11.3.20 Pacific Aluminium suggested the most critical issue was whether charges to generators could be 'sticky', *"that is, they must be as difficult to pass through in short-run offer prices to the wholesale electricity market as possible. If generators are largely able to pass through these costs by lifting their offer*

356 TrustPower submission, Redpoint analysis, p. 34-35

357 Unison submission, p. 14

358 MRP submission, Answers to Questions, p. 6

359 Smart Power submission, p. 13

360 Energy Link submission, p. 11

361 Genesis submission, p. 7

prices then they will have a much reduced incentive to participate efficiently in transmission investment debates and the dynamic efficiency gains that are sought will be much reduced". However, Pacific Aluminium notes that *"ultimately these increased costs will be passed through to consumers in the long-run through raising the cost of new generation investment"*.[362]

11.3.21 Fonterra considered that the proposal creates *"potential for Generators to over-recover their transmission costs"* by introducing a risk to their business and a variable charge that they will seek to recover from users by passing through the charge. According to Fonterra *"the end result being an increase in the cost of electricity energy and in some instances, Generators over-recovering their transmission costs" and "a distortion in the true cost of electricity"*.[363]

Disincentives to invest in peaking generation and early retirement of peaking and base load generation

11.3.22 Genesis suggested thatthe peaky nature of *"both the SPD charge and the RCPI charge may severely discourage investment in peaking generation, and will accelerate the retirement of existing peaking or firming generation".*[364]

Alternative $/MWh for generators

11.3.23 Some submitters, such as Meridian[365], Unison, Fonterra, and Powerco, expressed preference for a $/MWh based charge in place of the proposed RCPI charge.

11.3.24 Unison suggested that *"some form of $/MWh charge on generators should be preferred"* adding that *"this would very likely simply raise the spot/wholesale price by the marginal $/MWh rate". However Unison considered the "final incidence of the charge would all fall on consumers and distort the price signal relative to that potentially charged by distributors"*.[366]

11.3.25 Fonterra suggested that the residual component for generation should not be apportioned based on the peak injection (RCPI), as *"this will act as a disincentive for generators to build peak generation plants"*. Since it is not considered to be in the long term interests of NZ to discourage generation investments that are required to support increase in demand, Fonterra recommended the residual component for generation to be apportioned on a $/MWh basis.[367]

Powerco considered that due to the *"low price elasticity of demand for electricity, the net result would be that the bulk of the RCPI charge would*

362 Pacific Aluminium submission, p. 3-4

363 Fonterra submission, p. 4

364 Genesis submission, p. 7

365 Meridian submission, p. 49

366 Unison submission, p. 16

367 Fonterra submission, p. 5

become, in effect, a per MWh charge borne by all load". Powerco thus reasoned that, if generators were to be charged, the charge should be per MWh.[368]

Comments on 50:50 split between RCPI and RCPD

11.3.26 Many submitters commented on the proposed 50:50 charge allocation to generators and load.

11.3.27 Orion questioned the basis of which the 50/50 split of the residual between load and generation was arrived at[369] while Contact commented that the 50:50 split was *"at best arbitrary"*.[370]

11.3.28 TrustPower noted that the *"50:50 ratio is not commensurate with the benefits of transmission assets accruing to different parties"*. TrustPower suggested that *"using the half-hourly SPD benefit-based charge data produced by the Authority, the ratio of SPD charges between load and generators appears to be around 66:34"*.[371]

11.3.29 Meridian recommended changing the 50:50 ratio to 75:25, which it considered to be more aligned to international practise.[372]

11.3.30 NZX suggested that the portion of residual charges to generators and retailers/distributors is allocated *"according to their share of the previous year's SPD charge*". According to NZX, this would "*enhance alignment between the SPD and residual charge and minimise over-charging of beneficiaries"*.[373]

Number of peaks in the RCPI charge

11.3.31 Pacific Aluminium and Northpower expressed concern at the number of peaks used in RCDP and RCPI.

11.3.32 Pacific Aluminium noted comments by NZIER that the fewer the peaks in the RCPI charge, the more difficult it is to pass through the charge. Pacific Aluminium recommended that *"if the Authority decides to proceed with this , we recommend using as few peaks as possible"*.[374]

11.3.33 Northpower suggested that it was an opportune time to change to the average of 100 highest regional demands for the UNI (upper North Island).[375]

Detailed design not provided

[368] Powerco submission, p. 16

[369] Orion submission, p. 20

[370] Contact submission, p. 20

[371] TrustPower submission, p. 35 & p. 39

[372] Meridian submission, p. 46

[373] NZX submission, p. 9

[374] Pacific Aluminium submission, p. 5

[375] Northpower submission, p. 3

11.3.34 Two submitters commented on the Authority's decision to leave the detailed design of the RCPI charge to Transpower.

11.3.35 Unison advised that the Authority has not provided details on the design of the RCPI charge, instead expecting Transpower to design the charge, the reasons behind this being that *"where Transpower can identify situations where there can be 'efficient avoidance of peaks' then RCPI charges may be based on fewer peaks so that generators in constrained exporting regions would be incentivised to reduce generation during peaks"*. In relation to the above, Unison submitted that *"it is not clear why there needs to be a signal on top of the observed spot market signal of the costs of sending a marginal unit of electricity from an export-constrained region"*.[376]

11.3.36 Orion submitted *"we can imagine that it will need to be carefully designed to avoid perverse outcomes. We do not believe the analogy with RCPD is a reliable one"*.[377]

Gentailers advantaged over generators

NZGA submitted that *"where some charges are passed to generators that are integrated generator-retailers then opportunity for gaming is introduced. A generator-retailer can choose to pass its costs on at the retail end of the market while a merchant generator (of the type that many Maori Trust investors will be) will find its margins squeezed, and competition in the generation sector of the market may be suppressed"*.[378]

Net load

11.3.37 Many submitters, mainly those with distributed generation assets, submitted that residual charges should be based on net generation rather than gross generation.

11.3.38 CHH suggested that RCPI should be based on net load rather than gross load as is done now for RCPD.[379]

Opt out

11.3.39 Many submitter responses in relation to the residual proposal application to direct-connect customers, distributors and retailers where based on submitter's dissatisfaction with distributor's ability to opt-out of residual charges.

11.3.40 Please refer to question 27 for a more thorough review of submitter responses in relation to the opt-out facility.

Impact on distributed generation

376 Unison submission, p. 5

377 Orion submission, p. 22

378 NZGA submission, p. 6

379 CHH submission, p. 2

11.3.41 Pulse and Clearwater considered that *"it is important that embedded generators are paid for the real benefits that they bring to the market"* [380]and thus Pulse supported a greater emphasis (than the proposed 50%) on the RCPD charge[381], presumably because this would lead to reduce RCPI charges and greater ACOT payments to embedded generators which are based on RCPD.

11.3.42 Please note that a more detailed discussion of submitter comments in relation to distributor generation is addressed separately in a separate section of this summary of submission.

General comments

11.3.43 PwC considered that *"the proposal will not resolve issues relating to distributors and retailers rebundling transmission charges for mass market consumers as the low fixed charge regulations require transmission charges to be rebundled"*.[382]

11.3.44 MEUG submitted that the residual charge was important, citing the NZIER report prepared for MEUG which advised that the *"potential for dynamic efficiency gains in investment decision making hinge to a large extent on the ultimate incidence of there residual charges"*.[383]

11.3.45 NZ Steel argued that the residual charge proposal *"fails to differentiate the differing levels of benefit"* which requires consideration of *"transmission for varying distances, frequency and voltage support, backup for local generation"*.[384]

Proposal to allow distributors to opt out from the residual charge (Question 27)

11.3.46 20 submitters commented on the proposed opt-out facility. Of these comments, only PwC appeared to wholly support the proposal, while two submitters, Powerco and Vector, relayed what the Authority has interpreted as qualified support. 17 submitters did not support the proposed opt-out facility.

11.3.47 There appeared to be a misunderstanding of some submitters as to whether the opt-out proposal was intended to apply to residual charges only or whether it was also intended to apply to all interconnection and HVDC charges.

Support for the opt out clause

380 Pulse submission, p. 2

381 Clearwater submission, p. 9

382 PwC submission, p. 2

383 MEUG submission p. 33

384 NZ Steel, p. 2 & p. 14

11.3.48 PwC and Vector's (qualified) support for the opt-out clause was on the basis that it would assist distributors *"to mitigate residual charge volatility risk"*.[385]

11.3.49 PwC's noted that it made sense for distributors to be charged interconnection charges but it would support the opt-out clause if the Authority's SPD proposal went ahead.

11.3.50 However, PwC observed that *"suggestions that distributors do not respond to RCPD price signals because they are able to pass these costs through directly to consumers are misplaced"*.[386] PwC noted that distributors *"put considerable effort into managing Transpower peaks in order to reduce interconnection charges, and in our view, the current RCPD charge appropriately signals peak congestion times on the grid"*.[387] PwC advised that distributors' annual information disclosures suggest that distributors' shed about 5% of their load on average at the GXP peaks, which is a sizable reduction in peak load.

Not supporting opt-out

11.3.51 Many submitters disagreed with the opt-out proposal. A common issue with the proposal was the impact it may have on distributor load control.

Impact on load control

(i) TrustPower advised that the Authority *"has paid insufficient attention to the benefits of the current pricing signal being provided to distributors by the RCPD charge"*. TrustPower further stated that *"the existing RCPD regime does provide the correct incentives for those that hold (and can invest in) load control capability"*.[388]

(ii) Clearwater went further, advising that *"networks are the logic users of load control and they see the entire load on the network, retailers don't. Gentailers have mixed incentives as some times it may be in their interest for demand to rise, boosting the spot price"*. Clearwater concluded that *"giving the power to retailers without a balancing power from networks is extremely dangerous"*.[389]

(iii) PwC submitted that the Authority's *"suggestions that distributors do not respond to RCPD price signals because they are able to pass these costs through directly to consumers are misplaced"*.[390]

(iv) Contact submitted that it failed to see *"how charging retailers, as opposed to distributors (as per the current practice), can result in*

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385 PwC submission, p. 3

386 PwC submission, p. 3

387 PwC submission p. 8

388 TrustPower submission, p. 36

389 Clearwater Hydro submission, p. 7

390 PwC submission, p. 3

any increase in efficiency". In Contact's view, *"retailers are not well placed to manage this risk"*. [391]

Contractual and system issues

(v) New contractual requirements and system issues were another common theme from submissions. TrustPower, Powerco, ADHB, and Clearwater Hydro described a number of contractual issues with the opt-out clause.

(vi) TrustPower submitted that the *"loss of distributor's contractual relationship with Transpower (being) potentially problematic"*, a *"risk of (higher) transaction costs"* and potential for *"disputes in opt out process"*.[392]

(vii) Powerco suggested that the Authority *"further develop the legal arrangements that would apply, particularly with respect to the physical and notional embedding of generation assets and load control arrangements"*.[393]

(viii) ADBH advised submitter that *"if our network operator elected to opt-out this would negate a material portion of the benefits ADHB currently derives from its network services and connection agreement"* and then added that *"there is no guarantee that we would be able to make similar pass through arrangements with a retailer"*.[394]

(ix) Clearwater Hydro concluded that "*of all the (TPM) proposals this (opt-out facility) represents the biggest risk to (Clearwater's) systems and network security*".[395]

Mandatory arrangements

11.3.52 Vector submitted that *"the Authority should require that residual charges are applied to generators and retailers and remove the opt out/in option for EDBs"*. Vector further reasoned that it would be *"best to have a consistent approach across New Zealand rather than the potential for some EDBs to opt out, some to opt in, some to do a mix node by node, and some to change their approach over time"*.[396]

11.3.53 However, Vector noted that if the opt-out facility was to be implemented by the Authority, *"then EDBs should, subject to consultation, be able to opt out on any grounds"*. Vector considered that there should be *"no need to specify that it would depend on the extent that EDBs benefit from offering*

[391] Contact submission p.32

[392] TrustPower submission, p. 38

[393] Powerco submission, p. 17

[394] ADHB submission, p. 2

[395] Clearwater Hydro submission, p. 7

[396] Vector submission, p. 44

interruptible load. If EDBs benefit from this, they would take it into account".[397]

Impact on retailers

11.3.54 Genesis considered that the proposal would create unnecessary complexity by requiring retailers to undertake consultation with up to 29 distributors.[398]

11.3.55 Clearwater submitted that the opt-out clause would cause a much greater level of complexity and concluded that it would cause some retailers *"to stay off some networks due to the risks, costs and complexity, making customers on these networks effectively non contestable"*.[399]

11.3.56 According to Contact, *"while they (retailers) can set charges based on estimates, there is no ability for them to recover any differences during future periods"*. [400]

11.3.57 Contact considered that this *"is likely to be particularly difficult for smaller or new entrant retailers and may result in a decline of new entrants seeking to compete in the market"*[401].

Commerce Commission implications

11.3.58 Powerco recommended that the Authority *"investigate the relationship between the (Commerce Commission's) DPP*[402] *and the proposed residual charge"*. Powerco was of the view that this would assist the Authority to develop a residual charge that was compatible with distributor Commerce Commission regulation.[403]

Other

11.3.59 MRP submitted that *"the full extent and costs of the issues created (by the proposed opt-out facility) has not been considered or wrongly discounted in the Authority's analysis"*.[404]

11.3.60 Clearwater noted that "*embedded generators will find it very difficult to recover Avoided Cost of Transmission (ACOT) from a group of retailers*."[405]

11.3.61 Powerco recommended the Authority review the former Electricity Commission's decision that distributors and direct connects should be Transpower's legal counterparties at GXPs and subject to transmission

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397 Vector submission, p. 44

398 Genesis submission, p. 51

399 Clearwater Hydro submission, p. 7

400 Contact submission p.32

401 Contact submission, p. 32

402 Default Price Path (DPP)

403 Powerco submission, p. 16-17

404 MRP submission, Appendix A, p. 6

405 Clearwater Hydro submission, p. 7

charges. Powerco contended that the Authority should identify why the Commission's (previous) conclusions no longer apply.[406]

Whether the proposed residual charge, designed to encourage efficient avoidance of peak regional use of the grid, would best complement the beneficiaries-pay (SPD) charge (Question 28)

11.3.62 Of 27 submitter specific comments on question 28, seven submitters agreed[407] or partially agreed with the Authority's comment that the proposed residual charge was complementary with beneficiaries-pay, while 20 submitters did not agree with the Authority's comment.

11.3.63 Submitter comments are broken down into subheadings below.

Price signals versus minimisation of distortions

11.3.64 Transpower and ENA commented on the Authority's objectives for the residual charge, and the suitability of a price signal in residual charges.

11.3.65 Transpower submitted *"that it is important to be clear about the objective of the residual charge if applied in conjunction with the SPD charge. We understand from 5.6.71 that the Authority does not consider that the residual needs to incorporate price signals, but its proposal does not reflect this. We do not agree that the SPD charge, as proposed, would have the desired effect. It would therefore be necessary to retain the RCPD charge – which is designed to encourage efficient avoidance of peak regional use of the grid"*.[408]

11.3.66 ENA also questioned the objective of the residual charging, noting the Authority's quote in paragraph 5.6.71 of the discussion paper *"there do not appear to be strong reasons for the residual charge to incorporate price signals for more efficient investment"*. ENA also noted paragraph 5.6.72 which stated that the residual charge should be *"to the extent possible, be incentive neutral if other charges are introduced that provide incentives for more efficient investment"*. ENA requested that the Authority consider its objective for the residual charge.[409]

11.3.67 Orion submitted that if *"the objective is indeed minimizing distortion in use of the grid, as opposed to efficient peak avoidance, an allocation based on market share would seem to be more appropriate"*.[410]

Signal adequacy - RCPD/RCPI allocation

11.3.68 Powerco considered that the RCPD charge is appropriate for offtake, *"the RCPD charge is now well understood by offtake customers and it does*

406 Powerco submission, p. 17

407 Vector, ENA, CHH, NZX, Meridian, Pacific Aluminium, Powerco

408 Transpower submission, p. 9

409 ENA submission, p. 22

410 Orion submission, p. 21

encourage some efficient demand response. However, it would seem to be almost inept to implement an RCPI charge with intention of discouraging peaking generators from injecting during regional peaks".[411]

11.3.69 CHH supported the view that RCPD encourages efficient avoidance of peak regional use of the grid. It considered however, that *"there may well be issues with the RCPD signal being inadequately seen by many retail and small business customers"*.[412]

11.3.70 According to Unison, *"splitting the residual interconnection charge between generators and distributors seems likely to create distortions and reduce administrative efficiency: a)Generators only have the option of increasing $/MWh charges, thus increasing the marginal variable energy price signal. Unlike distributors, there is no possibility for generators to target transmission cost recoveries to the most inelastic consumers or consumer groups"*.[413]

Residual charge volatility

11.3.71 PwC submitted that *"the SPD charge will result in unnecessary and harmful volatility in the residual charge which creates a number of problems for distributors"* such as issues with compliance to the default price-quality path (DPP), and cash-flow volatility.[414] Clearwater and Energy Link[415] agreed that the residual would be volatile with Clearwater commenting that this would further reduce *"the certainty for new embedded generation projects"*.[416]

11.3.72 Fonterra submitted that volatility in the residual charge was somewhat due to the proposal to calculate SPD on a half-hourly basis.[417]

Implementation issues

11.3.73 MRP noted *"significant implementation details of the SPD method providing cause for concern about the (RCPD/RCPI) method's viability"*.[418]

Residual charge design recommendations

11.3.74 Submitters made a number of recommendations for amending the design of the residual charge.

11.3.75 Nova recommended that the allocation of residual portion *"should include:*

(a) RCPI charges on South Island generators

(b) Provision for deep interconnection charges on new generation

411 Powerco submission, p. 18

412 CHH submission, p. 13

413 Unison submission, p. 15

414 PwC submission, p. 3

415 Energy Link submission, p. 4

416 Clearwater Hydro submission, p. 8

417 Fonterra submission, p. 7

418 MRP submission, Appendix A, p. 7

(c) *Provision for charging recent projects for transmission upgrades*

(d) *A $/MWh or AMD-based charge for regions with abundant generation or transmission capacity, together with RCPD in other regions"*.[419]

11.3.76 Orion submitted that if "the objective is indeed minimizing distortion in use of the grid, as opposed to efficient peak avoidance, an allocation based on market share would seem to be more appropriate".[420]

11.3.77 DEUN considered that *"charges based on the 12 or 100 highest peaks in a region should be retained as the main residual charge after exacerbators-pay charge. And that these should, as at present, be charged to distributors rather than generator-retailers, as the latter will rebundle them according to their own pricing strategies"*.[421]

11.3.78 Genesis suggested developing a range of options for RCPI:

(a) *"put forward for comparative assessment during the consultation process a range of possible RCPI designs, including 12 peak, 100 peak, MWh charge, along with options for defining the regions used to determine the charges*

(b) *consider the impact and appropriateness of different percentage allocations to generation*

(c) *in combination with a more effective beneficiary pays approach, explicitly consider whether efficiency criteria are only satisfied if generators pass through 100% of these charges, meaning that direct allocation of all residual to load would be simpler and more appropriate*

(d) *discard the RCPI component altogether due to risk of unintended consequences, marginal additional benefit and theoretical economic efficiency criteria (mentioned in point above")*.[422]

11.3.79 Genesis suggested investigating a range of options for RCPD:

(a) *"allocate 100% of TPM charge to load on a RCPD basis*

(b) *allocate 100% of residual load on an RCPD basis*

(c) *remove demand price signals and allocate TPM charges to load on a MWh basis"*.[423]

Continuation of current arrangements

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419 Nova submission, p. 4

420 Orion submission, p. 21

421 DEUN submission, p. 6

422 Genesis submission, p. 49

423 Genesis submission, p. 49

11.3.80 NZGA favoured *"continuation of "postage stamp" pricing for Interconnection charges directed to load or distributors as it is currently"*.[424]

Whether the proposed RCPD/RCPI charge, would best meet the principles for an alternative charging option of minimising the distortion in use of the transmission grid resulting from the imposition of charges (Question 29(a))

11.3.81 26 submitters responded directly to question 29(a), with six submitters either agreeing or partially agreeing with the Authority's statement, and 20 submitters not agreeing with the statement.

11.3.82 Submitter comments are broken down into subheadings below.

Whether distortions are minimised

11.3.83 Many submitters commented on whether they considered the residual charge minimised distortions in the use of the transmission grid.

11.3.84 MRP submitted that *"the theory is clear that allocating charges to generators will result in distortions and the correct allocation is to loads"*.[425]

11.3.85 Powerco contended that *"the RCPD charge has the advantage of moving some way towards signalling the long run marginal cost of grid investment (albeit imprecisely) while retaining the main benefit of a postage stamp charge, which is the non-distortionary recovery of sunk costs (which comprise most of the grid costs)."*[426]

11.3.86 Phillip Wong Too advocated that *"residuals should be charged in a way that causes the least distortion in the electricity market, which I consider that the present mechanism largely achieves"*.[427]

11.3.87 NZ Steel advocated that the proposal *"does not take into account the proximity of generation to load. Charges on gross load and generation at connection points is inequitable and will lead to unintended consequences"*.[428]

11.3.88 Unison submitted that the *"(current) RCPD (postage stamp) charge is a (reasonably) allocatively efficient charge, because it seeks to avoid distorting use of inter-connection assets and nodal prices signal the SRMC of transporting energy".* In Unison's view *"an SPD-based allocation and RCPI charge would further distort nodal prices and create incentives to avoid the use of the sunk transmission network".*[429]

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424 NZGA submission, p. 7

425 MRP submission, p. 7

426 Powerco submission, p. 18

427 Phillip Wong Too submission, p. 3

428 NZ Steel submission, p. 15

429 Unison submission, p. 7-8

11.3.89 Unison further added *"under the current RCPD approach interconnection charges are levied on off-take customers (distributors and direct connect customers) based on year-preceding peak demands. While it is inevitable that this will create some behaviour distortions relative to the theoretically efficient marginal price of zero for use of a sunk asset (noting that nodal prices signal the SRMC of using the transmission grid), the approach nevertheless provides a low level of distortion and is efficient to administer"*.[430]

11.3.90 Orion submitted that *"the residual is such an uncertain and almost random charge that we do not consider that any response to it can be characterised as 'efficient'"*.[431]Pacific Aluminium agreed that the residual revenue should be recovered on a 50-50 basis from generators and load *"as this is effectively a tax its incidence should be as broadly based as possible and structured so as to influence production and consumption as little as possible, other than the stated aim of sending a signal to reduce consumption during peak periods in the UNI and USI"*.[432]

11.3.91 However Pacific Aluminium qualified its above statement by advising that *"whether RCPI meets these principles depends on its structure, which has not been specified"*.[433]

Further consideration of residual charge

11.3.92 MEUG submitted that *"the proposal to raise the residual revenue on the basis of RCPD and RCPI needs further consideration"*.[434]

11.3.93 Contact advised the Authority that it *"has not provided any tangible impact assessment on this significant methodology change from the status quo"*.[435]

11.3.94 Waipa cited a *"lack of clarity about how the RCPD and RCPI will be related and the lack of analysis regarding the ability of generators to 'game' this (charge)"*.[436]

11.3.95 Genesis advised that RCPI charges were largely undefined in the proposal.[437]

11.3.96 MEUG argued that, *"in extreme cases where clearly an investment is uneconomic, then Transpower should bear some of the pain with a partial asset value write down"*.[438]

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430 Unison submission, p. 15

431 Orion submission, p. 21

432 Pacific Aluminium submission, p. 19

433 Pacific Aluminium submission, p. 20

434 MEUG submission, p. 3

435 Contact submission, p. 33

436 Waipa submission, p. 1

437 Genesis submission, p. 50

438 MEUG submission, p. 13

Whether the proposed RCPD/RCPI charge, would best meet the principles for an alternative charging option of minimising the distortion ensuring the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered so future investment is not stifled by concerns by investors that they will not receive a return on their approved investment (Question 29(b))

11.3.97 18 submitters commented on the Authority's statement. Out of the commenters, five[439] submitters either agreed or partially agreed with the statement, while 13 submitters disagreed with the statement.

11.3.98 Powerco and NZX[440] agreed that the residual charge will fully recover required revenue. Powerco noted *"the RCPD method has been shown to be able to recover the balance of the full costs of providing the transmission grid not recovered by other charges"*.[441]

11.3.99 Unison contended that it is *"possible that imposing a charge on generators if it applies to past injections will lead to a substantial over-recovery of transmission costs, because in any given half-hour period it would be unknown at the time whether or not the injection would be subject to the transmission charge"*.[442]

11.3.100 NZ Steel advised that it is *"not realistic that any business can expect a full RoR on investments. If a return is to be assured, Transpower should be run on a cost minimisation basis, not a profit producing business"*[443] *ie an asset write-off is needed*.

Whether the proposed RCPD/RCPI charge encourages efficient avoidance of peak regional use of the grid (Question 30)

11.3.101 25 submitters responded directly to question 30 with six submitters agreeing or partially agreeing with the Authority's position and 19 submitters disagreeing with the statement.

Encouraging efficient avoidance

11.3.102 Orion questioned whether encouraging efficient avoidance contradicted with the objective of minimizing distortion in use of the grid.

11.3.103 NZX considered that the proposal provides *"incentives for generators and retailers/distributors to scrutinize transmission investments. It encourages efficient avoidance of peak use of the grid"*.[444]

439 NZX, Powerco, Meridian, ENA, Vector

440 NZX submission, p. 9

441 Powerco submission, p. 18

442 Unison submission, p. 15

443 NZ Steel submission, p. 15

444 NZX submission, p. 9

11.3.104 Transpower submitted that "*regular changes to RCPD would deter investment in load control and distributed generation*".[445]

11.3.105 Orion considered that the proposal would lead to *"less investment in the means by which peak avoidance is achieved"*.[446]

11.3.106 Genesis requested the Authority *"consider whether efficiency criteria are only satisfied if generators pass through 100% of these charges, meaning that direct allocation of all residual to load would be simpler and more appropriate"*.[447]

11.3.107 Simply Energy submitted that the *"TPM will undermine the price signal to manage load and embedded generation in line with Transpower's network because the benefit will be lower and the ability to predict periods of high cost will be significantly more complex"*.[448]

11.3.108 Pacific Aluminium suggested that the residual charge to generators *"should be structured in a way that makes it as difficult as possible to pass through in higher wholesale electricity prices in the short-run"*.[449]

11.3.109 Transpower suggested the *"only reason for this proposal is to reduce inadvertent price signalling by spreading the residual across more parties. This rationale is not compelling, because applying a charge to generators will increase unintended price signalling"*.[450]

11.3.110 NZ Steel highlighted the fact that for much of the grid there is now more than sufficient capacity for many years. NZ Steel considered that *"the proposal can be seen as a solution to yesterday's problem"* and that *"RCPD/RCPI charges need to reflect the level of benefit of being connected to the grid"*.[451]

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445 Transpower submission, p. 10

446 Orion submission, p. 21

447 Genesis submission, p. 49

448 Simply Energy submission, p. 2

449 Pacific Aluminium submission, p. 20

450 Transpower submission, p. 8

451 NZ Steel submission, p.16

RCPD regions

11.3.111 Transpower did not consider it beneficial to review the RCPD regions.[452] Transpower submitted that it *"cannot identify any clear benefit from reviewing the RCPD regions. The upper North Island and upper South Island regions are regions with an on-going need for incremental transmission investment. The current demarcation is well understood by participants, and is not intended to provide tightly targeted pricing signals"*.[453]

11.3.112 Norske Skog suggested that, given the *"recent transmission upgrades it may no longer be necessary to distinguish 4 separate regions, but rather it may be sensible to treat NZ as one region (and thus have a system peak charging methodology)"*.[454]

452 Transpower submission, p. 9

453 Transpower submission, p. 10

454 Norske Skog submission, p. 5

12. Proposal: PDP (Question 31)

12.1 Overview: PDP

12.1.1 The Authority proposed to extend the prudential discount policy so that it applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges.

12.1.2 The Authority also proposed to increase the maximum period of prudential discount agreements from the current period of fifteen years to the expected life of the asset to which the prudential discount policy applies.

12.2 What the Authority asked

12.2.1 Submitters views on the PDP proposal which enables prudential discounts as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges, and would may apply for the expected life of the asset to which the prudent discount applies **(Question 31)**

12.3 Feedback: PDP

Whether the proposed PDP should apply to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges, and whether parties may apply for the expected life of the asset to which the prudent discount applies (Question 31)

12.3.1 14 submitters expressed preferences on the prudential discount policy. 11[455] of these submitters either supported the Authority's proposal or broadly supported the concept of the proposal. Three submitters[456] did not support the proposal.

12.3.2 A number of submitters relayed that disconnection from the grid was unlikely. Contact advised that *"due to the nature of industrial load and its requirements around security of supply, industrial load will not disconnect from the grid"*[457] while MRP did not *"consider it credible that (any) disconnection would occur"*[458]. Contact did not see the prudent discount issue as material. Tuaropaki noted that it had limited bypass options relative to its competitors

[455] ENA, CHH, Smart Power, Clearwater Hydro, Meridian, Pacific Aluminium, Fonterra, NZX, Norske Skog, Transpower, MEUG

[456] Powerco, NZ Steel, Tuaropaki

[457] Contact submission, p. 34

[458] MRP submission, Appendix A, p. 8

thus it would likely be faced with the higher costs of subsidising the generators that receive the discounts.[459]

12.3.3 Transpower submitted that the *"prudent discount policy should not cover notional disconnection"* noting *"it is difficult to place a value on the various benefits of grid connection compared to self-supply"*. According to Transpower, *"grid connection generally allows a customer to readily expand their consumption, and provides reliability and quality benefits that self-supply is unlikely to match"*. Transpower also noted that *"It is difficult to determine an appropriate WACC for the annuity payment relating to a generation investment"*. [460]

12.3.4 Transpower advised that it supported the Authority's proposed amendment set out in question 31 (b), that an extension of the time period for a discount was warranted.

12.3.5 Meridian submitted that it was important that only credible business cases for alternative projects are eligible for the prudent discount. Meridian *"understands that the current process Transpower applies under the prudent discount policy to determine whether an alternative project is viable is robust in this regard"* and noted that *"this should continue under the revised prudent discount policy"*.[461]

12.3.6 Meridian also, like many other submitters, agreed with the extension of the policy to include:

(a) disconnection of load as a result of investment in generation

(b) extension of the time period for which the discount applies.[462]

12.3.7 NZ Steel described the PDP proposal as *"the tail wagging the dog"* and stated that the Authority's *"thinking needs to be reversed"* and that *"the asset owner should be pricing to attract net load to the connection point (as opposed to inefficient investment in alternative transmission options*)*"*.[463]

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459 Tuaropaki submission, p. 26

460 Transpower submission, answers to questions, p. 10

461 Meridian submission, p. 50

462 Meridian submission, p. 50

463 NZ Steel submission, p. 16

13. Summary of the CBA results (Questions 32 to 33)

13.1 Overview: Summary of the CBA results

13.1.1 The Authority prepared a quantitative analysis of the costs and benefits (CBA) of the proposed TPM and the option favoured by the majority of the TPAG (TPAG majority) against a counterfactual of the status quo.[464]

13.1.2 The CBA estimated the net present value of the economic costs and benefits of the options over a 30-year period using a real discount rate of 6.01 per cent real.

13.1.3 The result of the central case of the CBA of the proposed TPM was a net benefit of $173.2 million and for the TPAG majority option a net benefit of $49.3 million.

13.1.4 There were 33 submitters that provided comment on the CBA. Each of the submitters raised concerns about the CBA.

13.2 What the Authority asked

13.2.1 Submitters views on the CBA assessment of the economic costs and benefits of the proposal versus the counterfactual **(Question 32)**, and submitter views on the assessment of costs and benefits of the TPAG majority view against the counterfactual **(Question 33)**

13.3 Feedback: Summary of the CBA results (Questions 32 and 33)

13.3.1 Of the 33 submitters, the majority (32) did not support the Authority's approach to the CBA. One submitter provided an alternative CBA-type document that concluded that the proposed TPM was more efficient than the status quo but presented a preferred alternative TPM option to the Authority's proposed TPM.[465]

Approach and assumptions

13.3.2 Many of the comments on the CBA were in response to the analytical approach adopted by the Authority for the CBA.

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464 Refer to consultation paper.Appendix F- CBA of the TPM proposal. (Appendix F (Corrected).

465 Meridian submission included advice obtained from NERA Consulting Group which provides a qualitative assessment of the proposed TPM against the status quo. Meridian's modified option is discussed in more detail in paragraph 13.3.79.

13.3.3 The most common view was that the Authority's 'top down' approach to the CBA was too subjective and not appropriate for this type of proposal.[466] There were suggestions that the CBA could be improved by systematically addressing all the different elements of the proposed TPM and better describing and quantifying the benefits and costs.[467]

13.3.4 Genesis suggested that the Authority develop assessment criteria to allow a much clearer and more objective assessment of the current, and any future, TPM proposals.[468]

13.3.5 At least three submitters considered that a bottom up approach to a CBA would be preferable because such an approach creates a discipline on decision-makers to identify and evaluate the discrete impacts of any regulatory design proposal. Those submitters were of the view that such an approach would allow examination of any wholesale market distortions and reduced retail competition, would allow for more meaningful comment on assessments made in the CBA; and would generate recommendations for future changes.[469]

13.3.6 Further, submitters expressed the view that the Authority had not conducted a cross check of the findings from the top down approach to verify whether the application of the efficiency factor accords with the dynamic efficiency gains identified from the more conventional modelling approach which has formed the basis of previous reviews.[470]

13.3.7 Genesis and MRP attached consultant reports that contained alternative CBAs. The consultants both found that the proposed TPM would not yield a positive result. The findings from these reports are summarised in paragraphs 13.3.73 to 13.3.78.

13.3.8 Transpower submitted a report by economic consultant Competition Economics Group (CEG) who considered that the potential adverse consequences of the proposed TPM do not appear to have been wholly accounted for in the quantitative cost-benefit analysis. In CEG's view, the $173.2 million in net benefits found by the Authority is predicated on a belief that the proposal will promote dynamic efficiency. In CEG's view, the potentially substantial nature of additional costs suggests that the methodology may in fact not offer any net efficiency benefits and may instead impose a net cost on the market, if it is introduced.[471]

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466 See for example Genesis, p.38, Transpower, p.10; MRP, p.32.

467 See for example Genesis, p.39 and Appendix C Castalia report, p.11; MRP, pages.10, 33 and Appendix H Reunion report, p.13, TrustPower Appendix Redpoint Energy report, p.29.

468 Genesis submission, p.43

469 Genesis, p.39; MRP, p.33; TrustPower, p.48.

470 MRP submission, p.10

471 Transpower, Appendix B CEG report, p.8-9.

Scope of options assessed in the CBA

13.3.9 A number of submitters agreed that there is a need to address the allocation of HVDC costs but none supported the proposed TPM in its current form.

13.3.10 There was disappointment that the Authority assessed only one pricing proposal for changes to existing interconnection and HVDC charges and did not consider other alternatives. This was considered to be a procedural error as the Authority had not applied a CBA to the next best alternative.[472]

13.3.11 Several submitters considered that the analysis should be extended to consider a greater number of options.[473] In particular, there was a view that given the amount of analytical work that has been undertaken on this topic in the past that a wider scope of options should have been considered.

13.3.12 There was a view that the limited option analysis left a lack of clarity about whether bundling the HVDC cost pool with the interconnection cost pool is the best option.[474] It was suggested that several other topics warrant further assessment including: (i) the treatment of the HVDC charges, (ii) the classes of customer who should pay the interconnection charge and (iii) the design of the interconnection charge.[475]

13.3.13 Meridian put forward a modified option. While Meridian considered that the Authority's proposal was a substantial improvement from the status quo and would deliver efficiency gains, it proposed that the Authority consider some simplifications.[476]

Costs used in the CBA

13.3.14 The Authority identified four likely costs of the proposal. These were implementation costs; operational costs; costs of more complex models; and incentives on parties to alter their grid use in a way to minimise their exposure to the charge.[477] The Authority did not quantify the latter potential cost.

13.3.15 The Authority quantified the incremental one-off and ongoing costs of the TPM reform. These costs included: TPM design; transmission pricing system (TPS) development cost; participant TPS development costs (cost per

[472] MRP submission, Appendix H Reunion report, p.5.

[473] See for example Clearwater Hydro p.7; Contact, p.35; Electricity Network Association, pp.9-10; Genesis p.42 and Appendix C Castalia report, p.7.

[474] See for example Electricity Network Association, p.9-10, Genesis, p.38; MRP, p.31, Transpower, p.18. Vector, p.24.

[475] ENA submission, p.14.

[476] Meridian submission, p.7-8. The types of modifications to the proposed TPM suggested by Meridian included reducing the types and values of assets included in the SPD charge (value of $50 million to $100 million (or, at a minimum, $20 million); annual ex ante billing cycle; longer time period for benefits capping' splitting the residual postage stamp price 75 RCPD / 25 RCPI; no opt out for distributors; not subjecting retailers to SPD; and only embedded generators >10MW subject to SPD and residual.

[477] Consultation paper Appendix F(corrected) CBA, p.F 11.

participant and number of participants); and on-going TPS operating costs for both the pricing entity and participants (per participant and number of participants).[478] In the CBA, the present value of the cost of development and on-going operating costs was valued at $50.1 million.[479]

13.3.16 There was a common view that the TPM reform costs applied in the CBA have been underestimated. It was noted that the CBA attributes $5.9 million in implementation costs to the proposal. This estimated figure was largely considered by submitters to be too low.[480] The Authority's estimate was considered by submitters to be too low for the following reasons:

(a) Transpower submitted that the cost of implementing the proposals would be materially higher than modelled in the Authority's cost-benefit analysis. Transpower sought independent advice from PwC on the implementation costs. Based on PwC advice and the addition of $1.5 million for developing the pricing guidelines (opposed to the Authority's $0.5 million, Transpower's upper bound estimate of direct costs over the first six years was close to $30 million. The comparable figure used by the Authority was close to $15 million.[481]

(b) it was pointed out by several submitters that the proposed TPM is unique and has not been implemented in any other jurisdiction. Therefore there is a significant risk that the implementation of such an approach may reveal unanticipated implementation costs.[482]

Genesis expressed the view that the costs for a basic level of risk management under the proposed TPM would be significantly higher than the average one-off implementation cost of $125,000 per participant, and the average ongoing cost of $125,000 per participant per year applied on by the Authority's CBA.[483]

13.3.17 It was also submitted that the complexity inherent in the proposed TPM introduces new costs to market participants in the form of specialist staff, consultants, modelling, and legal advice. Retailers will seek to recover these new costs from consumers. Submitters considered that this complexity increases the cost of the proposed TPM relative to a simpler method.[484]

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478 Consultation paper Appendix F (corrected) CBA, p.F.16.

479 Consultation paper Appendix F (corrected) CBA, p.F.21.

480 See for example Contact, p.14, Genesis, p.24 and Appendix C Castalia report, p.39, PWC (on behalf of 22 EDBs), p.7, Transpower p.8, and Appendix A, p.10, TrustPower, p.43. It should be noted that several submitters in commenting on the cost of the proposed TPM referred to a report by PWC (2012). *Transmission Pricing Methodology - Impact Assessment.* Report for Transpower. Available online a https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Transpower-TPM-Impact-Assessment.pdf

481 Transpower submission, p.8.

482 See for example ACC, p.3, PWC (on behalf of 22 EDBs), p.7.

483 Genesis submission, p.24

484 Genesis submission, p.5

13.3.18 There was a view among these submitters that the Authority should undertake a more detailed investigation and analysis of the potential implementation costs and incorporate these into the CBA.

13.3.19 Further, it was suggested that development and on-going implementation costs should be validated with industry.[485]

Identification of other costs by submitters

13.3.20 Of the submitters that raised concerns about costs used in the CBA, a number of them also identified costs or 'dis-benefits' associated with the proposed TPM that the Authority did not to take into account in the CBA. The identified costs ranged from administrative and compliance costs through to incentives for perverse behaviour by market participants and other unintended consequences. The view was that these additional costs needed to be included in a revised CBA. These views are set out in greater detail below.

Costs of potential market distortions

13.3.21 The NZ wholesale market was described as being allocatively and dynamically efficient with prices set in reference to the short run marginal cost (SRMC) of generation for each half hour. Further, that the NZ market model results in locational price differences due to transmission losses and network constraints binding on the market outcome and that over time these price differences signal the need for investment.[486]

13.3.22 There were concerns raised by a number of submitters that the proposed TPM could potentially introduce distortions and perverse incentives into the wholesale market.

13.3.23 In particular, there were strong concerns about the proposal to introduce transmission costs that were sunk into the wholesale market pricing mechanism. Transpower submitted a report by consultants CEG who articulated this concern about the potential dis-benefits from the allocation of sunk costs. CEG advised that:

There can be no dynamic efficiency benefits associated with applying a 'beneficiaries pay' approach to reallocating the sunk costs of past investments. Sunk investment decisions have been made and there is now no way to reduce the cost or change the nature of those outlays. However, sub-optimal outcomes can be created through such reallocations, since they can result in large wealth transfers that may cause market participants to act in ways that compromise both static and dynamic efficiency.[487]

485 NZX submission, p.10

486 See for example TrustPower submission, Appendix Redpoint report, p.27

487 Transpower submission, Appendix B CEG report, p.2-3

13.3.24 This view was reiterated by several other submitters.[488] It was considered that the proposed TPM would likely create allocative inefficiencies, particularly from new distortions in the wholesale market.

13.3.25 The types of market distortions referred to in submissions include:

(a) adding a sunk cost allocation (through new transmission charges) to wholesale bid prices which would reduce allocative efficiency in the wholesale market. Under current arrangements, wholesale bids largely reflect short run marginal costs (operating and fuel costs) and result in least cost merit order dispatch of generation. The addition of sunk transmission costs into the wholesale bid will distort this efficient merit order dispatch[489]

(b) the proposed charging methodology creates a disincentive to offer highly efficient plant. This is viewed as perverse given that the incentive only exists in order to avoid charges for a transmission asset that is sunk. It was considered that this would raise prices, limit competition, and decrease the efficiency of the dispatch solution. It is estimated that the impact of these allocative inefficiencies is $25 million[490]

(c) the proposed TPM may disincentivise new generators from using under-utilised transmission capacity where the generator would be a significant beneficiary of an existing transmission asset. This may reduce the efficient use of the network[491]

(d) the introduction of the SPD model which would calculate benefits based on the existing offers in the bid stack, and recalculate prices without one element of the transmission system may introduce incentives for strategic bidding behaviour which would threaten least cost economic dispatch.[492] For example, generators would be incentivised to alter their bids away from SRMC in order to influence the counterfactual SPD calculations and avoid bearing a greater share of sunk costs of past transmission.[493]

13.3.26 Further, it was noted that the benefit calculation methods applied by the Authority failed to account for actual willingness to pay. The Authority's method assumed perfectly inelastic demand. Deadweight losses (in a static sense) would be too high because the charges are not appropriately calibrated to the various demand elasticities. A view was presented that the

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488 Refer to PWC submission (on behalf of 22 EDBs), p.5, TrustPower submission Appendix Redpoint report

489 Transpower submission, Appendix B CEG report, p.32

490 MRP submission, Appendix H: Reunion report, p.5; Appendix G Frontier report p iii-iv. Frontier advises that there is nothing intrinsic to a beneficiary pays approach as applied to existing transmission assets that ensures economically efficient outcomes.

491 TrustPower submission, Appendix Redpoint report, p.22

492 Genesis submission, Appendix C Castalia report, p.26

493 MRP submission, p.77

proposal risked doing more harm than good because those that are charged too highly would reduce their demand by too much, and would over-invest in ways to minimise their grid demands. Therefore more of the costs would need to be shouldered by others.[494]

13.3.27 It was noted that these new potential distortions did not appear to be included in the cost/benefit assessment.

13.3.28 It was suggested that the allocative inefficiencies identified by submitters needed to be incorporated into the analysis. Further, there was a view that the Authority needed to investigate and include the costs of any wholesale market distortions which may practically arise from the proposed SPD charge.[495]

13.3.29 Another perspective was that is not worthwhile to risk compromising the efficiency of the wholesale dispatch process in this manner in order simply to identify the private beneficiaries of a past (sunk) investment and to facilitate a series of 'welfare neutral' wealth transfers. And that there is no sound economic basis for designing the TPM in a way that might cause generators to restructure their wholesale bids to avoid incurring sunk costs.[496]

Increased volatility, risk premium and costs

13.3.30 Several submitters presented the view that the proposed TPM would significantly increase price volatility and 'amplify' risk through the supply chain including generation, retail and the distribution.[497]

13.3.31 MRP referred to an assessment by Frontier Economics that found that the impact of volatility and uncertainty would increase costs to industry which will ultimately flow through to end use consumers in the form of higher prices for delivered energy.[498]

13.3.32 There was a view that the introduction of volatility into transmission charges on an ex post basis could lead to some form of risk premium being factored in to generator bids and retailer margins. On this basis, there was a suggestion that the Authority should formally consider the potential efficiency losses resulting from the impact of its proposal on dispatch.[499]

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494 MEUG submission, attached NZIER report, p.20-21

495 ENA submission, p. 10, PWC (on behalf of 22 EDBs), p.5

496 Transpower submission, Appendix B – CEG report, p.34

497 See for example Electricity Network Association, p.7, Genesis, Appendix C Castalia report, p.27; Transpower, Appendix B CEG report, p.39-42

498 MRP submission, p.74

499 Contact submission, p.35.

13.3.33 The reasons for increased volatility and risk premiums outlined in submissions included:

(a) generators would face uncertainty about cash flows resulting from ex-post charging and this may result in additional risk premiums being incorporated into wholesale prices[500]

(b) retailers are likely to face more volatile prices arising from the new SPD interconnection charge and more volatile generation charges. Retailers (in particular, small retailers) would have limited ability to hedge these risks. In turn, this is likely to result in retailers incorporating higher risk premiums into their prices[501]

(c) the effect of the SPD proposal on the cash flow of distributors was also raised as a concern. PwC, on behalf of 22 distributors, submitted that the use of half-hour trading periods, is unwarranted and will result in higher transaction costs and risk for distributors.[502]

13.3.34 There was a view that the proposed TPM will lead to greater uncertainty and result in an increased cost of capital in the industry. In particular, the SPD methodology was viewed as a step change in complexity compared to the current TPM. Several respondents submitted noted that if implemented, it would be one of the most complex cost allocation methodologies globally by virtue of being linked to wholesale market outcomes. Those submitters expressed the view that the ultimate result of the significant additional complexity is uncertainty. Such complexity creates significant issues for participants about how the incidence of charges will change and how to accurately forecast potential liabilities. Uncertainty could contribute to industry wide risk premiums and ultimately costs to consumers.

13.3.35 There was a view that the use of half-hour trading periods will result in higher transaction costs and risk for sector participant generators' cash-flows will also be less certain, which may result in additional risk premiums being incorporated in wholesale (and, in turn, retail) prices. The consequence is that prices in the wholesale market could increase across the board.[503]

Detrimental impact on wholesale and retail competition

13.3.36 There was a concern that the proposed TPM would have an adverse impact on retail and wholesale competition and that the Authority needed to incorporate an assessment of competition impacts into its analysis.[504]

13.3.37 It was considered that competition impacts will be felt more strongly by new entrants, and small, independent retailers. There was a view that the the

500 Transpower submission, Appendix B CEG report, p.39

501 Transpower submission, Appendix B CEG report, p.40-41. Genesis, Appendix C Castalia report, p.28

502 PWC submission, p.9-10

503 Transpower submission, Appendix B CEG report, p.39, TrustPower, p.44

504 See for example Electricity Network Association, p.10, Energy Link, p.11-12, Genesis, p.6 and Appendix C Castalia report; p.29; MRP, Appendix H Reunion report, p.7; Orion NZ, p.13

proposed TPM will impact risk management practices of retailers by introducing non-spot market risk for which there is no natural hedge. It was considered that this could result in significant cash-flow problems for small and new entrant retailers; and may also result in increased prudential requirements from Transpower and/or distributors. These factors could increase barriers and complexity for new and independent retailers and embedded generators. [505]

13.3.38 A further concern was that the proposal may encourage generators to retail only in areas close to their generation assets, resulting in reduced competition in retail.[506]

13.3.39 There was a view expressed by some submitters that the SPD charge and the RCPI charge may severely discourage investment in peaking generation. Those submitters expressed the view that a peaky RCPI charge and an uncapped SPD charge that focuses on high priced periods would reduce the potential revenue for these assets thereby attaching a higher risk profile to these assets. This could affect investment decisions in existing plant and any potential new peaking or firming plant.[507]

13.3.40 Some submitters expressed concern that the complexity of the proposals are such that smaller retailers would face a significant increase in on-going costs to invest in improved systems and highly skilled personnel in order to estimate the impacts of transmission related costs to its business.[508]

13.3.41 Those submitters expressed a view that the significance and impact of the new TPM on embedded generation in particular could have an unanticipated and very significant impact on these past investment decisions, the viability of the business and the confidence to invest in any future long term generation assets. These concerns were raised noting that the long term generation investment decisions have been based on the current TPM and the benefits of the investments recognised by Part 6 of the Electricity Industry Participation Code.

Costs of administration

13.3.42 Some submitters said that the Authority needed to factor in administrative and additional compliance costs of any new system. It was thought that even a relatively small increase in administration costs would impact on the overall CBA numbers given that total PV of net benefits of the proposed TPM is only $170 million. In addition to new administrative costs, the cost of preparing

505 See for example Genesis, p.6 and Appendix C Castalia Report, p.28; Transpower, Appendix B CEG report, p.7; Wind Association, Meridian, p.37

506 TrustPower submission, Appendix Redpoint report, p.45

507 Genesis submission, p.36

508 MRP submission, p.76

submissions for the Authority's review of TPM was cited as a cost that should be factored into the CBA.[509]

13.3.43 Other submitters listed a range of other administrative costs including administering, under the proposed TPM, five types of charges rather than the current three; new resources to predict the SPD (and potentially the RCPI) charges; continuous interaction with the system operator to facilitate current and accurate expectations forecasts. This was contrasted with an RCPD approach which has a simpler basis from which to assess liability.[510]

Benefits used in the CBA

13.3.44 The Authority identified two main benefits of the proposal relating to the HVDC and interconnection component of the proposed TPM. The benefits were *"wholesale market benefits"* (or *"dynamic efficiency"*) and avoided dispute costs (or *"durability"* benefits).[511] The dynamic benefits were calculated by applying an efficiency factor of 0.3 per cent to the industry baseline revenue.

13.3.45 Many submitters were very concerned about the approach used in the CBA to estimate the benefits arising from the proposed TPM. These concerns related to both the use and justification of the efficiency factor approach by the Authority; and the assumption that there will be benefits of reduced disputes arising from the proposed TPM. In general there was a view that the benefits used in the CBA were overstated.

13.3.46 There was uncertainty expressed as to whether the estimated efficiency benefits arise from just the SPD allocation, or from a combination of all components of the proposed TPM (LCE, SPD, and RCPD and RCPI). It was noted that much of the commentary in the Authority's CBA only applied to the SPD method, whereas the proposal should be assessed in its entirety.[512]

13.3.47 There was particular concern raised about the Authority's application of the efficiency factor. CEG submitted that this efficiency factor is not estimated; it is assumed. Therefore, taking a lower (higher) parameter will reduce (increase) the estimated economic benefits.[513] A number of submitters supported the view by CEG. In particular, concerns were raised that the efficiency factor approach was subjective and unorthodox.[514]

13.3.48 The main criticisms were that that the approach used is subjective and based on an assumption that the proposal would be beneficial, rather than provide a robust quantified assessment of its expected impact. There was a view that

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509 ENA, pp.17-18, NZ Wind Energy Association, p.3

510 Genesis submission, Appendix C Castalia Report, p.40

511 Consultation paper Appendix F (corrected), p. 15

512 Genesis submission, Appendix C Castalia report, p.13

513 Transpower submission, Appendix B CEG report, p.16

514 See for example Genesis, p.38; MRP, p.31 and Appendix E, *Quantification of Dynamic Efficiency Gains*; TrustPower, p.40

the CBA methodology is practically guaranteed to provide a net benefit because it simply asserts that there are dynamic efficiency gains, and applies a mark-up factor (of 0.3 per cent).[515] On this basis, some submitters said that the CBA cannot be relied on as support for the proposal. There was also a view that the approach is not appropriate for regulatory design proposals.[516]

13.3.49 Several submitters questioned the validity of the qualitative assessments cited by the Authority in justifying its use of the 0.3 per cent efficient factor. It was noted by several submitters that the examples used by the Authority (such as the Commerce Commission's calculation of total factor productivity) have no relevance to transmission pricing. Therefore, according to the submitters, the examples cannot provide any real insight into the appropriateness of the assumption about the efficiency factor. [517]

13.3.50 Several submitters attached a number of independent reports by economics consultants which included criticisms of the method of calculating dynamic efficiency and in particular the use of an efficiency factor to determine dynamic efficiency benefits.[518] Broadly, the concerns raised in the independent reports included:

(a) the Authority has used the approach to estimating dynamic efficiency benefits that is applied by the Commerce Commission in merger decisions. The comment was made that dynamic efficiency estimates in merger cases attempt to quantify the effects from a loss of innovation that will occur due to the removal of a participant from the market. In contrast, the dynamic efficiency gains from changing market settings (such as the TPM) come from providing signals to investors that guide them towards more optimal decisions on investment timing and location. On this basis, it was not considered appropriate to adopt the Commission's approach to assess the effects of changes in regulation or market design[519]

(b) one submitter's independent report raised concerns that the Authority applied the efficiency factor to compounded growth in sector revenue rather than as a simple reduction in (total generation and transmission) costs. According to this submitter it meant that the actual implied factor was around 3.1 per cent which is significantly higher than the Authority's 0.3 per cent. Therefore, on this basis the dynamic efficiency

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515 See for example ACC; p.3, Business NZ, p.3, Major Electricity Users' Group and attached NZIER report, Genesis, Appendix C Castalia report, MRP, Appendix C Castalia Report, Ringa Matau Ltd, NXZ Energy

516 See for example Genesis submission, p.38

517 See for example MRP, p.34; Transpower, Appendix B CEG report, p.16; Vector, p.45

518 Genesis submission, Appendix C Castalia report, Major Electricity Users' Group attached report by NZIER, MRP, Appendix C Castalia Report, MRP, Appendix H Reunion report, Transpower, Appendix B CEG report, TrustPower Appendix Redpoint report

519 See for example Genesis submission, Appendix C Castalia report, p.11, TrustPower Appendix Redpoint report, p.28

benefits of around $17 million are observed rather than the Authority's $172 million[520]

(c) another perspective was that the efficiency factor should be applied to transmission revenues rather than gross industry revenues. This is because the TPM only applies to grid costs and not whole of industry costs. This approach implies a net economic result of negative $27.8 million in the Authority's central case.[521]

13.3.51 There were concerns raised about the Authority's assertion that the proposed TPM will result in dynamic efficiencies.[522] This main reason for this concern, as referred to in the discussion on costs, was based on the argument that there can be no dynamic efficiency benefits from applying a beneficiaries-pay approach to sunk costs. Several submissions stated that there are no international examples of transmission pricing arrangements that involved the continual reallocation of sunk costs.[523]

13.3.52 There was a view that rather than create dynamic efficiencies, the continual reallocation of sunk costs in manner proposed by the Authority would result in significant inefficiencies and a systemic increase in risk throughout the supply chain. On this basis, there was a view that the basic premise of the proposal was questionable.[524]

Benefits of more efficient transmission investment

13.3.53 The Authority considered that the proposed TPM will promote efficient transmission investment through increased transparency and placing stronger incentive on parties to participate in investment making decisions. Therefore the proposed TPM would achieve improvements in dynamic efficiency as the SPD method will identify the beneficiaries of grid investments more accurately and this will encourage greater lobbying of the Commerce Commission by the deemed beneficiaries. As a result of this increased lobbying, the Commission's capital expenditure approval decisions will be more efficient.[525]

13.3.54 There was general disagreement with the Authority's position that the proposed TPM would result in dynamic efficiency benefits of the magnitude outlined by the Authority.

13.3.55 In general, submitters were not persuaded by the Authority's assertion that the proposed TPM would lead to greater participation in the investment decision-making and approval process.

520 MRP submission, p.10 and Appendix H Reunion report, p17

521 MRP submission, Appendix I Covec report, p.19

522 ACC, AECT, Business NZ, CCH, Contact, ENA, Genesis, MEUG, Norske, MRP,

523 MRP submission, p.18; and Appendix H Reunion report, pp.4-5; Transpower, Appendix B CEG report, p.3

524 Transpower submission, Appendix B CEG report, p.3; Genesis, Appendix C Castalia report, p.30

525 Consultation paper Appendix F (corrected) CBA, p. 11

13.3.56 Several submitters observed that the proposed TPM, if implemented, would not change the administrative processes that apply to transmission capital expenditure decisions and would not improve dynamic efficiency.[526] The reasons for this view is that the Grid Investment Test (GIT) would not be modified in any way and total energy costs for most off-take customers are no more than a few per cent of their total costs and transmission is less than 10 per cent of total energy costs. It was suggested that this does not seem to provide a sufficiently material incentive for customers to engage more directly with the grid investment decision-making processes – other than for some very large off-take customers and generators. On this basis, the view was held that there would be little if any impact on improving dynamic efficiency of the transmission investment assessment processes.

13.3.57 There was a view that Authority has not presented any evidence to suggest that the upgrade approval process over the past decade has suffered from a lack of quality information; or has led to any investments which could be deemed `inefficient'; or could have been improved in any way.[527] Transpower contended that there is no evidence of problems of systematically poor grid investment approval decisions. Further it does not accept that the SPD charge would improve transmission investment decisions. Instead, in its view there is a risk the SPD charge could have an unintended effect of delaying or obstructing efficient investments.[528]

13.3.58 Further, it was noted that the current grid upgrade arrangements have been in place only since 2010 and more time is needed before making any assumptions that further benefits are possible.[529]

13.3.59 It was noted, regardless of whether there are possible efficiency benefits from the proposed TPM, that there limited opportunities for industry participants to participate in the decision-making processes for transmission upgrades with a project value of less than $20m. This suggests that any benefits may only arise if the Commerce Commission changes its thresholds to allow industry participants greater opportunities to provide input into base capital expenditure decisions.[530]

13.3.60 Several submitters questioned the size of the potential benefits from the proposed TPM given that in recent years Transpower has undertaken a large investment program of around $2 billion. As a result of this recent round of investment, it is considered that there will be little requirement for investment in grid upgrades for a number of years. Therefore it was suggested that the level of efficiency benefits may not be as great as suggested in the CBA.[531]

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526 Powerco submission, p.10

527 Genesis submission, Appendix C Castalia report, p.29; Transpower submission, p.21

528 Transpower submission, p.21

529 TrustPower submission, p.1-2

530 TrustPower submission, p.2

531 See for example NZ Steel, Norske, MRP and Appendix H Reunion report, Orion Energy, p.22.

Several submitters pointed out that most of the major transmission investment decisions have already been made, and there is unlikely to be any further significant expansion of interconnected grid capacity for the next 15 years.

13.3.61 Other submitters maintained that the suggested benefits attributed to more efficient transmission investment are likely to be overstated in the CBA. The main reasons for the view were that:

(a) the SPD charge does not directly impact Transpower's investment decisions, and therefore its future interconnection revenue requirement, and so the charging mechanism is reduced to a complex revenue allocation approach[532]

(b) it is questionable whether the SPD charge information will be materially beneficial to submitters in lobbying actions because most parties already understand which transmission assets are of benefit to them[533]

(c) that market participants may have incentives under the proposed mechanism to lobby for asset investments *"not simply on the basis of the direct costs and benefits of the asset in question, but on the basis of how that asset will affect...their interconnection charges"*. There was a view, that such behaviour could lead to inefficient transmission investment decisions, the opposite of what is intended[534]

(d) the SPD method proposed by the Authority is not likely to correctly identify beneficiaries. Some of the reasons provided include that the Authority's assumption that everything remains equal (in terms of demand, offering behaviour and even generation and transmission configurations) is unjustifiable; the use of the unserved energy value in the counterfactual may not always be valid; differing basis for the identification of beneficiaries between the GIT and the Authority's SPD test; transmission investment considers factors that are external to the energy only market, such as voltage, power quality, aspects of voltage and frequency stability.[535]

13.3.62 On this basis, it was suggested by submitters that the benefits of more efficient investment decisions need to be revised down in the CBA.

13.3.63 There was criticism of the Authority's assessment that the transmission investments that potentially could be deferred by implementing the proposed TPM would yield a potential benefit of $67 million. It was asserted that the correct figure is likely to be much lower because the projects considered in the Authority's assessment relate to generation projects that have subsequently been deferred or are likely to be uneconomicMRP asked why

532 PwC submission, p.4

533 PwC submission, p.5

534 Transpower submission, Appendix B CEG report, p.3 Supported by PWC, p.5

535 MRP submission, p.32 and Appendix H Reunion report, p.10

reliability projects were included in the Authority's assessment given the there is no private benefit from them under the SPD approach.[536]

Benefits of reduced disputes and associated costs

13.3.64 The benefits incorporated in the Authority's CBA included durability benefits, that is, the benefits of avoided costs of on-going disputes over the method for allocating transmission charges. The Authority considered that the proposed TPM will result in less ongoing lobbying for change to the TPM. The benefit of avoided costs of on-going disputes was estimated at $36.5 million in present value terms.[537]

13.3.65 The Authority's claim was strongly disputed by a number of submitters.[538] In particular, concerns were expressed that:

(a) the proposed TPM will be significantly more complex to administer than the current TPM, which would increase lobbying

(b) there are likely to be significant implementation issues that will need to be consulted on and revisions are likely in order to fine tune the proposal over time

(c) the changing nature of wholesale market will also create new winners and losers, and therefore new lobbying positions, overtime. Lobbying issues associated with the proposed TPM are therefore likely to be enduring

(d) disputes will also arise in relation to model inputs and on issues such as the capping of the SPD charge. It was noted that the 50/50 split of the residual allocation itself appears to have no rigorous basis, and could easily become a future area of dispute

(e) that creating a distinction between assets commissioned before and after 28 May 2004 would increase the scope for disputes. Submissions stated that by treating those asset classes differently, the Authority would incentivise some customers to oppose the replacement and refurbishment of particular assets. Submitters also expected to see many disputes about the definitions of assets and their treatment by the SPD method

(f) parties would have an incentive to continually agitate for changes to the SPD in order to reduce their own transmission charges

(g) it was submitted that a complex model-driven pricing method with large wealth transfers would invite dispute.

536 MRP submission, p.10

537 Consultation paper Appendix F (corrected) CBA, Table 7, p.F 15

538 See for example Genesis, p.18 and Appendix C Castalia report, pp.30-31; MRP, p.36 and Appendix H Reunion report, p.25; PWC (on behalf of 22 EDBs), p.6; Transpower, p.11-12; and Appendix B CEG report p.20-29, TrustPower, p.2 and attached Redpoint report, p.30-31, Unison Networks, p.13.

13.3.66 Further, Transpower raised the concern that unconstructive engagement in grid planning processes would increase planning and decision costs, and could delay efficient investment.[539] Parties could advocate against efficient investments (or for inefficient investments), not because of the private costs and benefits of the new investment in question, but because they care primarily about the allocation of sunk costs in relation to post 2004 assets.

13.3.67 Some submitters considered that the proposal will increase rather than decrease dispute and lobbying costs. Those submitters did not think the Authority's assumptions regarding durability and reduction in disputation costs were credible and need to be reassessed.[540]

13.3.68 Contrary to these views, one submitter (Meridian) considered that as the SPD method is refined over time, it is reasonable to expect that the number of disputes will diminish. The main reason given was that the socialisation of the costs of North Island grid upgrades and the current cost allocation of the HVDC link are stressing the durability of the current regime. [541]

The net result of the CBA

13.3.69 Several submitters doubted the benefit of implementing such a significant change to the TPM. The two key concerns were that firstly, the overall benefits of the proposed TPM were small and uncertain and secondly, that the Authority's CBA itself was flawed.

13.3.70 Pioneer stated that, given the net present value of the proposal is only \$173.2 million over 30 years (with a sensitivity range of \$85 million to \$269 million) the central case is equivalent to a benefit of approximately \$12 million per year in an industry with total revenues of \$6.5 billion – or 0.2 per cent.[542] Pioneer were of the view that, overall, the benefits seem to be very small for the amount or risk being incurred by consumers.

13.3.71 EnergyLink expressed a view that many of the assumptions were based around how parties would behave and what may or may not happen in parallel futures with or without the proposed TPM. In all, the benefits were very small given the risks of the proposed TPM.[543] A common sentiment was that the limit to the level of potential benefits relative to the potential for unintended consequences led to the question `Is it worth the risk?'

13.3.72 CHH applied the Authority's efficiency factor/pricing analysis to its own situation and calculated that, if those outcomes transpired, it would save 1 per cent. It concluded that the minimal level of saving did not justify the proposed TPM.

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539 Transpower submission, p.10

540 ENA submission, p.11, Genesis, Appendix C Castalia report, p.31-32, Transpower Appendix B CEG report, p.3-5

541 Meridian submission, p.62

542 Pioneer submission, p.5.

543 Smart Power submission, p.15-16

13.3.73 Genesis submitted a report by Castalia consultants that presented an alternative analysis based on a ‘bottom up’ (rather than ‘top down’) approach to the CBA.[544]

13.3.74 Castalia asserted that the proposed TPM could have some benefits in moving towards a more optimal combination of transmission, generation and load investments in the future. These benefits, however, are outweighed by significant unintended impacts that are detrimental to the efficiency of the wholesale and retail markets. In Castalia’s view, the unintended consequences result from the application of the SPD charge and the way that the residual RCPD/RCPI charge is designed. In its analysis of the proposal, Castalia estimated:

(a) that the cost of the unintended consequences (inefficient dispatch, higher peaking charges, impact on competition); and higher implementation costs informed by Transpower results in a finding that the net benefit of the proposed TPM is negative $48.2 million compared to the Authority’s finding of a net benefit of positive $173.2 million.[545] The analysis (focusing on the SPD charge) took the “bottom up” estimate of the problem with the current TPM of $97 million (from Appendix C of the Authority’s consultation paper).[546]

13.3.75 Castalia reduced this dynamic efficiency benefit by:

(a) efficiency losses associated with inefficient dispatch and a decline in retail market competition:

(i) efficiency losses from inefficient wholesale market outcomes which has a present value of $40 million over 30 years

(ii) efficiency losses from reduced retail competition of a present value of $54 million over 30 years

(b) not including the Authority’s estimated benefits of avoided dispute costs[547]

(c) including an additional $9.5 million to Transpower’s costs (based on work by PwC for Transpower).[548]

13.3.76 Based on its findings, Castalia suggested that the TPM proposal needed to be redesigned in order to meet the Authority’s objective.

13.3.77 MRP engaged Reunion to undertake an alternative CBA which in summary considers there are significant net costs to the proposal of negative $182 million over a 30 year NPV. Reunion considered that dynamic efficiency

544 Genesis submission, Appendix C Castalia report

545 Genesis submission, Appendix C Castalia report, p.42

546 Genesis submission, Appendix C Castalia report, p.37

547 Genesis submission, Appendix C Castalia report, p.38

548 Genesis submission, Appendix C Castalia report, p.41

benefits from the Authority's proposal are likely to be closer to zero given the current benign outlook for supply and demand for the foreseeable future.[549]

13.3.78 The Reunion analysis asserted that the proposed TPM would result in:

(a) $25 million of loss in allocative efficiency from less efficient dispatch of more expensive generation[550]

(b) $90 million of loss due to the additional working capital required across the supply chain to manage the volatility associated with transmission charges[551]

(c) the costs associated with participant implementation costs and maintenance should be increased given the complexity and uncertainty of the proposal, taking the figure from negative $50 (Authority's estimate) to negative $67 million[552]

(d) the benefits of $36.5m in avoided disputes cannot reasonably be claimed. They estimate these benefits at zero. However, MRP notes this is likely to be conservative as it believes that the scope for dispute will actually significantly increase.[553]

Meridian's modified option

13.3.79 Meridian presented a qualitative assessment of its modified proposal against the Authority's proposal. Meridian said that adopting it's modified proposal would: reduce participant transaction and potentially dispute costs (interpretability); reduce Transpower's setup and ongoing operational costs; reduce volatility of private costs (as share of new asset costs < $50-100m is certain); reduce cost uncertainty for participants (by avoiding the need for Transpower to reconcile charges to each ICP, and be subject to the Code reconciliation timeframes).[554]

13.3.80 Further, by maintaining the current contract counterparties (Transpower to distributors) this will increase incentive for management of peak demand and increase coordination between distribution network development and transmission loadings; reduces transaction costs (no need for Transpower to contract with 34+ retail participants); reduces transaction costs for embedded generators (no need to contract with retail participants for ACOT revenues); and reduces transaction costs (no need to establish additional/separate prudentials with Transpower and distributors).

Uncertainty about treatment of embedded generators

549 MRP submission, p.35 and Appendix H Reunion report

550 MRP submission, Appendix H Reunion report, p.22

551 MRP submission, Appendix H Reunion report, p.24

552 MRP submission, Appendix H Reunion report, p.26

553 MRP submission, Appendix H Reunion report, p.25

554 Meridian submission, p.64

13.3.81 A number of submitters raised concerns around the uncertainty of the impact of the proposed TPM on embedded generators. There was a view that the Authority must carefully consider and clarify the treatment of embedded generation.[555]

13.3.82 One submitter submitted that small embedded generation may well be an important part of innovation in the electricity sector. Submitters contended that the proposed TPM as may increase uncertainty and difficulties for these smaller players which in turn will dampen innovation in the electricity sector. Enabling innovation was considered to be a key part of an efficient system. Submitters also recommended the cost benefit analysis look at whether the TPM encourages or discourages innovation.[556]

13.3.83 Another perspective provided was that some embedded generation has been free-riding on the transmission system, resulting in inefficiencies and that no assessment was made of the benefit gained from removing the perceived ability for embedded generation to 'free-ride'.[557]

13.3.84 The submitters who raised the issue of embedded generation requested clarification and incorporation of the impacts into the CBA.

Submitter analysis - wealth transfers

13.3.85 The Authority noted that the proposal may create wealth transfers but that these are not losses to society in general. The submitter impacts are described by the Authority but are not included in estimating the economic benefits and costs. [558]

13.3.86 While the Authority did not seek views on submitter analysis, there were a number of submitters that commented on the detrimental impact of wealth transfers, such as that of reallocating sunk costs, under the proposed TPM. [559]

13.3.87 There was criticism that the Authority had not undertaken a robust analysis of wealth transfers that may affect dynamic efficiency in its CBA. In particular, it was noted that wealth transfers are likely to arise in relation to historical investments that were made based on the current TPM, which may be impaired if the proposed TPM is adopted.

13.3.88 There was a concern that the Authority's proposal would have significant wealth transfer and value implications for existing generation assets. That is, the significant ex-post cost reallocations could lead to incentives to recover

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555 See for example Alinta, p.1, Buller Electricity, p.12, CHH, Contact , Major Energy Users' Group and attached NZIER report, p.39,MRP, p.6, NZ Steel, Norske Skog, p.5, Pioneer, PWC (on behalf of 22 EDBs), p.7.

556 NZ Wind Energy Association submission, p.2

557 Contact submission, p.6 and 15

558 Consultation paper Appendix F (corrected), p.F 24

559 See for example Transpower submission Appendix B CEG report, p.14

transmission charges in ways that would likely distort wholesale market outcomes to the detriment of consumers.[560]

13.3.89 Further there was a concern that decisions that result in significant wealth transfers increase investor perceptions of regulatory risk and undermine the confidence overseas capital providers have in the stability and predictability of the New Zealand energy sector. It was thought that this would negatively impact investment incentives.[561]

13.3.90 It was suggested that the regulatory uncertainty created by the Authority's proposal not only has implications for the costs of future generation developments (increasing risk premiums and hurdle rates), but also would adversely impact the cost of capital for other (non-electricity related) infrastructure investments.[562]

13.3.91 It was pointed out that that prices that South Island generators paid for their assets reflected the expectation of paying HVDC charges in perpetuity. The concern was that to pass these charges onto other parties would amount to a significant wealth transfer from the consumer to South Island generators.[563]

13.3.92 Some submitters considered the proposed TPM would erode investor confidence significantly.[564]

13.3.93 It was recommended that the Authority include efficiency cost implications arising from wealth transfers in its CBA.[565]

TPAG majority proposal

13.3.94 The CBA for the Authority's proposed TPM was compared against the transmission pricing approach supported by the majority of the Transmission Pricing Advisory Group (TPAG).

13.3.95 The overall result of the aggregated analysis, for the central case of the TPAG majority view was a net benefit of \$49.3 million. This result was considered to be substantially lower than the findings for the proposed TPM which provided for a net benefit of \$173.2 million.[566]

13.3.96 There were a number of submissions that provided views on the Authority's comparison between the proposed TPM and the TPAG majority proposal.

13.3.97 Meridian agreed that the TPAG majority proposal would likely result in net economic benefits, although it suggested that the estimated difference

560 MRP submission, p.19

561 PwC submission (on behalf of 22 EDBs), pp.5-6. TrustPower, p.45

562 MRP submission, p.19

563 Norske Skog submission, p.8

564 MEUG attached NZIER report, p.26; Norske Skog, p.8

565 PWC submission, p.6

566 Consultation paper, Appendix F corrected CBA , p.4

between the net benefits of the TPAG majority and Authority's proposal may be smaller than the Authority has estimated.[567]

13.3.98 Some submitters considered that the Authority's analysis created uncertainties. It was submitted that the Authority adopted different assumptions to the TPAG, but it was not clear what those assumptions were or why they differed. Submitters also stated that this appeared to lead the Authority to select an efficiency factor more than four times greater than that used for the TPAG majority proposal.[568]

13.3.99 One submitter said that great care needs to be taken with the TPAG majority proposal, especially in the light of recent developments where South Island generation proposals have been cancelled due to flat or declining demand.[569]

13.3.100 Vector did not agree with the Authority's assessment. It asserted that the TPAG majority proposal would result in: (i) over-investment in South Island generation (generators would not need to take into account the long-run transmission cost implications of investing in generation in the South Island); and (ii) substantial wealth transfers from consumers to South Island generators.[570]

13.3.101 One submitter agreed with the assessment of the costs and benefits of the TPAG majority proposal against the status quo, as the figures seemed consistent with the TPAG's own analysis which it broadly supported. However, that submitter went on the say that it considered that the net economic benefit of the Authority's SPD-based proposal would be negative and that if all costs were included this would make the TPAG majority proposal the preferred approach.

13.3.102 Another submitter considered the benefits of the TPAG majority were estimated with more accuracy (and using a more robust method) in 2011. There was the suggestion that the Authority should refer to the bottom-up analysis undertaken for TPAG to assess benefits. Further, this submitter considered the TPAG majority option preferable to the Authority's proposed TPM.

13.3.103 It was pointed out that in Table 7 (section 5.7 of the consultation paper) the benefit cost ratio of the Authority's proposal is approximately 4:1. In contrast, the ratio of the TPAG majority view was 56:1. It was presented that in light of the significant uncertainty of the benefits over time of the proposed TPM, that the Authority should give further consideration to a lower-cost alternative.[571]

567 Meridian submission, p.66

568 Transpower submission, p.11

569 Pacific Aluminium submission, p.21

570 Vector submission, p.49

571 TrustPower submission, p.49

14. Assessment against the Authority's objective (Question 34)

14.1 Overview: Assessment against the Authority's objective

14.1.1 The Authority's objectives in relation to the TPM are to promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers.

14.1.2 The Authority considers that its proposal achieves its objective for the TPM to facilitate efficient investment in the electricity industry and efficient operation of the transmission grid, generation (including distributed generation), distribution networks and demand-side management.

14.2 What the Authority asked

14.2.1 Submitters views on the consistency of the proposal with the Authority's objective for the TPM **(Question 34)**

14.3 Feedback: Assessment against the Authority's objective

Whether the proposal is consistent with the Authority's objective (Question 34)

14.3.1 Approximately half of the submitters specifically stated that they did not agree that the proposal meets the Authority's objective while around half of the submitters did not specifically comment on the proposal's consistency with the Authority's objective. One submitter (Meridian) agreed that the proposal was consistent and one submitter (Smart Power) broadly agreed that the proposal was consistent with the Authority's objective.

14.3.2 EMA submitted that the Authority's statutory objective is "*to act in the long term interests of the NZ consumer*". EMA noted that it is difficult to see how more expensive, more volatile, and less secure power achieves this goal.[572] Ringa Matau also submitted that the added complexity of the proposal would not likely be in the long term interest of consumers. Pioneer argued that the proposal would cause higher prices[573] with Phillip Wong Too indicating that the proposal would foster a perception that New Zealand is a risky place to do business and would result in a risk premium (and ultimately higher electricity prices).

[572] EMA submission, p. 4

[573] Pioneer submission, p. 17

14.3.3 PwC, on behalf of 22 distributors, argued that wealth transfers which are inherent in the Authority's proposal, undermine confidence, and will have a negative impact on dynamic efficiency and thus the proposal is not considered with the Authority's objective.[574] The ENA, on behalf of 29 distributors, "*does not consider the Authority has demonstrated, relative to its statutory objective, a case for the substantial change in the TPM that it is proposing*". ENA further argued that "*the proposal risks higher consumer prices, creating substantial winners and losers within the industry, triggering further lobbying and litigation, and incurring certain additional costs for uncertain benefits*".[575]

14.3.4 Powerco disagreed that the proposal is consistent with the Authority's objective, stating that the cost benefit analysis provided did not consider all the costs of the proposal and that, if it did, "*the net national benefit of the Authority's TPM proposal would be negative if all costs were included.A net negative economic impact would be inconsistent with the Authority's objective*".[576]

14.3.5 MRP argued that "*existing, and new entrant retailers in particular, will be commercially affected due to the additional working capital needed to manage increased market volatility exacerbated by variable transmission charges*". In MRP's view, this will reduce competition (including price and service offerings) to consumers and "*appears to run counter both to the Authority's statutory objective and the core cost allocation principles against distorting energy markets*".[577]

14.3.6 DEUN considered that "*consumer actions to reduce peak loads, and therefore network costs, are economically efficient in their own right, whether or not they maximize total economic surplus*" and that adverse effects on consumer incentives to take action should be considered in assessing the proposal's consistency with the Authority's objective.[578]

14.3.7 Taharoa C Block submitted that the changes will cause a loss of energy in the system and impact reliability of transmission services, and that the proposal does not adequately consider impacts on distributed generation.[579]

[574] PwC submission, p. 5

[575] ENA submission, p. 14 -15

[576] Powerco submission, p. 21

[577] MRP submission, p. 12

[578] DEUN submission, p. 3

[579] Taharoa C Block submission, p. 2,

15. Impacts on distributed generation

15.1 Overview: distributed generation

15.1.1 The Authority's initial view was that it was the responsibility of participants' and interested parties' to assess the impacts of the proposal on distributed generation. A decision was made to include a section on distributed generation following the high level feedback on DG that was noted by the Authority in industry submissions.

15.2 Feedback: Impacts on distributed generation

Assessment of the impacts of distributed generation

15.2.1 29 submitters did not support the proposal's treatment of distributed generation while 23 submitters did not comment on the impacts of distributed generation. Two submitters, Meridian and Contact, either supported or partially supported the proposal's treatment of distributed generation.

General issues

15.2.2 Ventus submitted that Government initiatives over the last eight or so years have looked to improve the penetration of independent generation and distributed generation into the market, however the Authority's proposal `*seems to run contrary to all these historical and present initiatives'.* Buller Electricity Electricity supports this view, citing a disconnect between the encouragement of distributed generation as reflected in Part 6 of the Code, and the Authority's TPM proposal.

15.2.3 MainPower advised that "*new entrant embedded generators will be discouraged because it will be difficult to assess transmission charges from the methodology, and it will be equally difficult to formulate the commensurate offset through the wholesale prices*"[580].

15.2.4 PwC submitted that the Authority should carefully consider and clarify the treatment of embedded generation in the proposed TPM. This includes clarifying how a node which is the site of injection and off take will be classified for the purposes of regional coincident peak ('residual') charges*.*

15.2.5 PwC considered that the proposal could have "*flow on repercussions for distribution and generation investments*"[581]. PwC listed the following as adverse impacts of the proposal on distributed generation:

(a) distributed generators will need to pay directly billed transmission charges for the first time

[580] MainPower submission, p.3

[581] PwC submission, p.2

(b) avoided transmission payments (subsidies) will be lower

(c) greater volatility in avoided transmission payments.

10 MW threshold in the SPD model

15.2.6 Clearwater Hydro expressed concerns that it would be "*seen by the SPD model*"[582] due to the actions of others. Clearwater argued that since all its assets are less than the 10MW threshold, it would not expect to be included in the proposed SPD calculation. However, since the Authority's proposal involves combining generation at each GXP, if the total of all generation is greater than 10MW, Clearwater would be included within the SPD calculation. Clearwater went on to argue that if any new generators were aware of the consequences of a decision to build then they can make an informed decision, however this is not the case for sunk assets. Clearwater recommended that the proposal be changed to ensure than all embedded generators less than 10 MW be excluded from the SPD calculation.

15.2.7 Meridian also recommended that generators should only be included in the SPD calculation if they were greater than 10MW.

Avoided cost of transmission (ACOT)

15.2.8 Energy3 contended that "*a key part of developing the financial viability of projects is to forecast electricity sales revenue and the Avoided Cost of Transmission ("ACOT") payment*". Energy3 advised that the Authority's proposal made the future quantum of ACOT revenue difficult to predict. Energy3 went on to point out that it was "*not looking for a subsidy for providing a service but rather for clarity on the payment of an existing revenue stream that recognises the significant benefits of embedded generation in improving the efficiency of the electricity system*". [583]

15.2.9 Energy Link advised that the quantum of ACOT payments under the Authority's proposal will reduce significantly "*because ELBs (Electricity Lines Businesses) would only pay the residual RCPD-based charges, and these would comprise a much smaller portion of the total transmission charges than they do now"*.[584]

15.2.10 Pioneer submitted that the *"total value of these payments is approximately $30 million (for approximately 2,700GWh in 2011)*'" and that under the proposal the RCPD charge "*could be a third of the current level*" and thus ACOT payments may reduce to a third of current levels. Pioneer also considered that the current RCPD charge "*recognises the value of peak demand management over the long term*" and therefore should be preserved. [585]

582 Clearwater Hydro submission, p.6

583 Energy3 submission, p.2

584 Energy Link submission, p.2

585 Pioneer submission, p.3-4

15.2.11 Clearwater and Meridian submitted that the functionality whereby distributors can `opt out' of residual transmission charges may result in distributed generators needing to recover ACOT from retailers. Clearwater and Meridian see this as potentially problematic.

Gross injection versus net injection

15.2.12 Norske Skog pointed out that while the consultation paper states that distributed generation is charged based on net injection via paragraph 7.6.2 of the consultation paper, the Authority has expressed other views in meetings and there was a question as to whether gross or net generation would be used to calculate residual charges.

15.2.13 CHH suggested that the Authority should "*use net load or generation at location points as the case may be*".[586] Net load was considered to be a fair methodology by many submitters as it was not considered equitable to charge generators for grid injections in net off take situations.

Other

15.2.14 Pioneer advised that it had concerns about system operator discretion to have its distributed generation dispatched. This could result in Pioneer incurring SPD charges over which it had no control.

15.2.15 Nova submitted that "*in regions where there is an abundance of generation capacity (Taranaki), or recent lines upgrades (Auckland) there is little benefit in providing additional incentives for distributed generation while that situation persists*". According to Nova, "*in those circumstances where there is excess inter-regional grid capacity it seems appropriate to apply at least part of the total interconnection fee at the GXP level on $/MWh demand or Anytime Maximum Demand type charge, rather than RCPD"*.[587]

15.2.16 NZ Steel advised that for "*embedded generation with a net demand there is far less benefit from the grid, than for generation located some distance from load*".[588] According to NZ Steel, the proposed TPM fails to differentiate between these two circumstances.

586 CHH submission, p.2

587 Nova submission, p.4

588 NZ Steel, p. 2

16. Evaluation of alternative means of achieving the objectives (Questions 35 to 37)

16.1 Overview: Evaluation of alternative means of achieving the objectives

16.1.1 The Authority considered various alternative methods for establishing charges to recover transmission costs, including market and market-like approaches, beneficiaries-pay approaches and other alternative approaches.[589]

16.2 What the Authority asked

16.2.1 To inform its thinking on alternative approaches to achieves its objectives, the Authority sought submitter comments about the Authority's:

(a) evaluation of alternative market-based and market-like approaches for the recovery of transmission costs **(question 35)**

(b) acceptance of the TPAG's evaluation of alternative exacerbators-pay approaches for the recovery of network reactive support costs **(question 36)**

(c) assessment and conclusions about alternative beneficiaries pay options for establishing transmission charges to recover HVDC and interconnection costs **(question 37)**.

16.3 Feedback: Evaluation of alternative means of achieving the objectives

16.3.1 A dominant theme that emerged from submissions is a desire to see the Authority undertake further analysis and consider alternatives.

16.3.2 Connected with the desire for the Authority to undertake further analysis and consideration of alternatives, is the view that the analysis of the alternatives also needs to include additional detail on the impacts of the alternatives.

16.3.3 In terms of the different classes of alternatives:

(a) there was generally a lack of support for the use of market-based or market-like approaches

(b) there was some support for the Authority's acceptance of the TPAG's evaluation of alternative exacerbators-pay approaches

[589] For further information see consultation paper chapter 6

(c) there was mixed support for alternative beneficiaries-pay approaches. Some of the approaches suggested included zonal postage stamp, flow tracing, expansion of deep sunk cost allocation, and the forecast model approach.

Alternative market based and market like approaches (Question 35)

16.3.4 13 submissions[590] provided direct answers to question 35, with some submitters providing extensive comments.[591]

16.3.5 In relation to the Authority's evaluation of alternative market-based and market-like approaches, the key point made by submitters was that it was not appropriate to apply such alternatives to electricity transmission pricing. For example:

(a) TrustPower noted that "…*successive regulators have concluded that 'market-based', 'market-like' and beneficiaries-pay approaches have only limited application to transmission services*."[592]

(b) similarly, MRP proffered that *"it confirms the view put forward by a number of participants to the framework consultation that the application of market-based and market-like mechanisms to monopoly infrastructure like transmission has little benefit*."[593]

16.3.6 However, Pacific Aluminium submitted that it was not clear why a market-based approach, such as capacity rights, could not be implemented given the similarities between the market required for this option and the FTR market.[594]

16.3.7 A second key objection that was raised in submissions was that market-based and market-like alternative approaches would be impractical to implement. For example, Transpower commented *"the alternative market-based and market-like approaches for recovery of interconnection and HVDC charges…are not feasible within the existing framework."*[595]

16.3.8 In addition, there were some comments made about the lack of consideration of the further impacts of these alternative options.

(a) TrustPower expressed concern that *"…the existence of multiple tiers creates a number of further effects which have not been evaluated."*[596]

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590 See submissions from Clearwater Hydro (p. 11), MEUG (p. 14), Meridian (p. 50-51), MRP (Appendix A, p. 8), Norske Skog (p. 17-18), NZX (p. 11), Orion (p. 23), Pacific Aluminium (p. 21), Powerco (p. 21), Smart Power (p. 17-18), Transpower (Appendix A, p. 11), TrustPower (p. 51), Vector (p. 46)

591 See for example, Meridian (p. 50-51), Norske Skog (p. 17-18) and TrustPower (p. 18)

592 TrustPower, p. 52

593 MRP, Appendix A, p. 8

594 Pacific Aluminium, p. 8

595 Transpower, Appendix A, p. 11

596 TrustPower, p. 52

(b) Smart Power noted that *"…there was no summary which weighted up the pros and cons for each option and said we decided it was not as suitable as the proposed methodology because (sic) xxx…"*[597]

16.3.9 There was little comment expressed as to the Authority's view on the lawfulness of the market-based and market-like alternatives, and no clear consensus amongst those that did respond. However, a small number of submitters put forward the view that lawfulness is a concept that is subject to change over time. For example:

(a) MEUG suggested that *"more consideration of the merchant transmission option should be made because, while it may be unlawful to include such an option in the TPM, it may be a good economic solution and it's the regulatory regime that needs to change to accommodate such an option."*[598]

(b) Orion noted that *"some have been ruled out on the basis that they are not currently lawful. But law and regulation itself can be changed."*[599]

Alternative exacerbators-pay charging options (Question 36)

16.3.10 There was uniform agreement from those that responded[600] (ten) for the Authority's acceptance of the TPAG's evaluation of alternative exacerbators pay approaches for the recovery of network reactive support costs. Support for the quality of the TPAG work was high.[601]

16.3.11 Two submitters, Smart Power and Transpower, provided additional comments relating to the level of kvar charge. [602]

The Authority's assessment and conclusions about alternative beneficiaries pay options for establishing transmission charges to recover HVDC and interconnection costs? (Question 37)

Ten submitters commented on question 37. Of these ten submitters, four submitters agreed with or partially agreed with the Authority's assessment, while six submitters disagreed with the Authority's assessment

Issues with the analysis

16.3.12 A number of submitters had issues with the Authority's analysis. For example:

597 Smart Power, p. 17

598 MEUG, p. 14

599 Orion, p. 23

600 See submissions from Clearwater Hydro (p. 11), MEUG (p. 15), Meridian (p. 56), MRP (Appendix A, p. 8), NZ Steel (p. 17), Pacific Aluminium (p. 22), Powerco (p. 21), Smart Power (p. 18), Transpower (Appendix A, p. 11), TrustPower (p. 52)

601 For example, see submissions from Meridian (p. 56), Smart Power (p. 18) and Pacific Aluminium (p. 18)

602 See Transpower, Appendix A, p. 11 and Smart Power, p. 18

(a) Smart Power submitted that there was no "*real overall conclusion at the end of each option*" and while the "*assessment of costs and benefits does it to some extent but not fully as it really just relates to the cost benefit not to the other issues such as practicality etc*".[603]

(b) Norske Skog noted that the Authority's proposal and alternative options are predicated on the assumption that the electricity market is perfectly competitive and market power does not exist. Norske Skog considered that this assumption "*is false – and without a perfectly competitive market many of the economic arguments used by the Authority simply do not stack up*".[604]

(c) MEUG referenced the opening sentence of paragraph 6.5.14 which states "*The option of using economic models is considered superior to the status quo, but inferior to the Authority's proposal to use SPD to identify beneficiaries and private benefit*." MEUG advised that it did not think the consultation paper provides the evidence to support this statement.[605]

(d) MEUG then advised that the next sentence of paragraph 6.5.14 (the argument that the SPD allocation method is superior to than economic models) is stated as "*That is because, unlike the Authority's proposal, it (that is economic models) would not use direct wholesale market outcomes to determine benefit but rely instead on forecasts and modelling assumptions*." MEUG noted that "*a fundamental flaw in the SPD proposal is that the consumer surplus is calculated using non-market assumptions rather than actual bids. Therefore the criticism that economic models use non-market assumptions can also in part be levelled at the SPD allocation method*".[606]

Potential for dispute

16.3.13 Transpower and Smart Power suggested that economics models, flow tracing, and zonal beneficiaries-pay all have the potential for dispute.[607]

Commerce Commission regulation conflicts

16.3.14 MRP agreed with the Authority that it is not lawful for it to establish certain alternative beneficiaries-pay mechanisms due to the overlap with Commerce Commission. However, MRP argued that "*material issues of overlap exist with the Authority's proposal that are not resolved*".[608]

Options for future consideration

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603 Smart Power submission, p. 18

604 Norske Skog submission, p. 18

605 MEUG submission, p. 15

606 MEUG submission, p. 15

607 Smart Power submission, p. 19

608 MRP submission, Answers to Questions, p. 9

16.3.15 NZX advised the Authority to engage further with industry to elicit alternative options.[609]

16.3.16 Orion advised that "*the fundamental question is whether dynamic SPD based assessment of benefits is materially better than possible other beneficiaries-pay approaches. We think a more enduring and stable cost allocation linked to benefits could be devised that achieved much the same result at much less cost*".[610]

16.3.17 Fonterra recommended the following alternative beneficiaries-pay methods are considered in more detail:

(a) Flow tracing methodology

(b) "*Expand the deep sunk asset allocation: this ensures that costs are known in advance, there is no risk premium attached. However, fuel sources cannot move so could hinder investment by Generators*.

(c) *Forecast model approach: Prior to transmission asset investments being made, allocate the costs to the beneficiaries using a commercial model*".[611]

16.3.18 TrustPower considered that if the Authority "*had taken into account the problems with the SPD method highlighted in this submission it might have found that an economic model approach would be superior to the SPD method as it a)provides a clear link between transmission planning and cost allocation .b)would not be based on market outcomes so would not have any adverse impact on static efficiency c) would require significantly fewer incremental implementation and on-going costs*".[612]

16.3.19 TrustPower also considered that the Authority might also have "*found that the zonal beneficiaries-pay method is superior to the SPD method, noting the existing TPM has already illustrated that splitting the country into four regions can work*". TrustPower suggested "*differentiated $/MW charges for the existing RCPD regions would be one simple way of implementing this*."[613]

16.3.20 Clearwater considered flow tracing "*to offer the best alternative to recover HVDC cost compared to the status quo as it can provide inter year price certainty, a methodology to migrating charges as the use of the system changes but still provide investor with price stability*". Clearwater suggested that "*limits could be placed on inter year variability to provide stability*".[614]

16.3.21 Powerco suggested that the "*zonal postage stamp approach (sometimes called "licence plate") may have merit*". However, Powerco advised that it

609 NZX submission, p. 11

610 Orion submission, p. 23

611 Fonterra submission, p. 3

612 TrustPower submission, p. 53

613 TrustPower submission, p. 53

614 Clearwater submission, p. 11

would need to see more detail before it could reach an informed conclusion.[615]

[615] Powerco submission, p. 21

17. Proposed Guidelines for Transpower (Questions 38 and 39)

17.1 Overview: Proposed Guidelines for Transpower

17.1.1 The Authority has prepared draft guidelines to be followed by Transpower in preparing a methodology for allocating Transpower's revenues to transmission customers.

17.1.2 The draft guidelines provide specific direction for connection charges, static NRS changes, interconnection charges and HVDC, residual charges, prudent discount policy, and loss and constraints excess.

17.1.3 The Authority considers that Transpower should develop the TPM so that it is consistent with the Authority's objective in 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.

17.2 What the Authority asked

17.2.1 The Authority sought submitter views about whether guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option, asking:

(a) do you consider that the draft guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? **(Question 38)**

(b) do you have any suggestions for amendments to the draft guidelines to ensure that they provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? **(Question 39)**

17.3 Feedback: Proposed Guidelines for Transpower

17.3.1 While some parties considered the draft guidelines were adequate, many parties considered that the draft guidelines did not provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option. Submitters suggested more detail, in order to reduce the operational discretion given to Transpower in developing a revised TPM. MEUG and NZ Steel felt that left with discretion, Transpower would not give appropriate consideration to consumers' interests.

17.3.2 Transpower and others suggested that since the guidelines draw heavily on the Authority's proposed TPM changes, the changes should be addressed in advance of consideration on the content of the guidelines. Orion submitted that there were technical issues that might cause difficulties in implementation and these issues should be explored before detailed design commences.

17.3.3 Some of the submitters did not support the guidelines on the basis of their opposition to the Authority's proposal in general, or issues with particular parts of the Authority's proposed TPM.

17.3.4 Vector considered that the Authority has exceeded its mandate and gone beyond the development of developing mere guideline, thus encroaching on Transpower's mandate to develop a TPM. Vector recommended that the Authority restrict itself to developing guidelines and principles.

Whether draft guidelines provide the sufficient guidance (Question 38)

17.3.5 17 submitters commented on question 38. Four submitters[616] supported or partially supported the draft guidelines while 13[617] submitters did not support the Authority's draft guidelines.

17.3.6 Smart Power considered the draft guidelines appeared reasonable "*on the basis of the preferred option as it stands*".[618] Some submitters opposed the draft guidelines on the basis of opposition to the proposed TPM changes, which were described briefly in the draft guidelines. For example, Clearwater Hydro's opposition to the draft guidelines were based on its disagreement with "*using SPD to calculate interconnection charges 7.6.1, 7.6.2…RCPI 7.7.2, and 7.7.3 and the ability to opt out 7.7.4*".[619] Powerco submitted that "*the guidelines appear adequate for the Authority's purpose, but note that Powerco disagrees with some major elements of the TPM Proposal and so would recommend that these guidelines not be adopted*".[620]

Not enough guidance

17.3.7 CHH, Meridian, Pioneer, Transpower, MRP, and TrustPower submitted that the draft guidelines should include more detailed guidance on implementation, to reduce operational discretion and improve uncertainty.

17.3.8 CHH suggested that more detail was required in the draft guidelines because they didn't "*think (the draft guidelines) will give effect to the benefits the EA have assumed in the proposal. Any new guidelines developed will need sufficient detail that will leave no room for misunderstanding by market participants or Transpower as to how they should be developed as a methodology*".[621]

616 Powerco, Meridian, Norske Skog, Smart Power

617 Clearwater Hydro, CHH, Pioneer, Transpower, Orion, TrustPower, Vector, Contact, Nova, Pacific Aluminium, NZ Steel, MEUG, MRP

618 Smart Power submission, p. 20

619 Clearwater submission, p. 12

620 Powerco submission, p. 21

621 CHH submission, p. 17

17.3.9 Meridian went further than CHH. While Meridian agreed the draft guidelines provide the necessary guidance to Transpower, it suggested they "*could be improved significantly if the Authority gave greater guidance to Transpower. Our points here are linked to our recommendation that the SPD charge in particular could be made more acceptable by improving its transparency and removing the design of important parts of the charge from Transpower's discretion. As we noted above, it is important that Transpower's operational discretion is limited where there is value at stake and that the process, in particular for creating the counterfactual, is transparent*".[622]

17.3.10 Meridian went on to suggests the types of details that should be included within the draft guidelines, so to avoid Transpower's operational discretion, submitting that "*rules will need to be established in the guidelines for a range of issues including: whether the counterfactual state is security constrained, i.e. does it meet the same dispatch standards for instantaneous reserves, N-1 stability and thermal constraints; and how situations where there is insufficient energy to meet demand are managed. The same can be said for the residual charge. There may be a benefit in providing greater detail in the guidelines about aspects of the residual charge, such as: whether the charge is a MW or MWh charge; and the regions for calculating RCPI and RCPD."*[623]

17.3.11 Meridian suggests it would also be helpful *"if the guidelines for the residual charge confirmed that embedded generators (>10MW) are subject to the residual charge. The guidelines for the SPD charge confirm that embedded generators are subject to that charge, and the absence of embedded generators from the list of those subject to the residual charge could be construed as a deliberate leaving out of those parties".*[624]

17.3.12 Similarly, Pioneer "*does not agree that the draft guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option. As discussed in answer to question 23 and 26, Pioneer submit that the Authority must consult again when it has developed more detailed proposals, particularly in relation to the residual charge and threshold for application of the SPD charge to generating stations. In our view it is the role of the Authority, and not Transpower, to determine this detail which has the potential to alter incentives and the efficiency of the electricity market. The analysis required to develop the detail of any residual charge must take account of the benefits of embedded generation to the efficient operation of the electricity market. We support the creation of a working group to assist the Authority in developing the necessary detail for the TPM Guidelines*".[625]

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[622] Meridian submission, p. 68

[623] Meridian submission, p. 68-69

[624] Meridian submission, p. 69

[625] Pioneer submission, p. 18

17.3.13 MRP opposed the guideline, submitting that "*the draft guidelines omit significant details, the resolution of which will either give rise to oversimplification and lack of meaningfulness or excessive complexity vulnerable to on-going debate*".[626]

17.3.14 MEUG stated that "*the guidelines need more clarification of how the residual is to be treated because that will be highly contentious as some parties will as a result of summing their SPD allocation and residual allocation pay more for transmission than the benefits they derive. This will result in inefficient incentives and outcomes*". MEUG went on to note that "*Transpower is indifferent to these effects on its customers and flow on effect to end consumers; whereas the EA should have an appreciation of the scale of likely inefficient outcomes and incentives and give commensurate greater guidance to Transpower".*[627]

17.3.15 Consistent with MEUG view, NZ Steel considered that "*it is necessary the guidelines and/or interaction with Transpower allow an informed view on the full economic impact of the charges that would result on a user/user group basis*". NZ Steel further contended that "*Transpower will be indifferent to these effects on consumers. EA needs to have a full appreciation of likely inefficient outcomes and give guidance to Transpower*".[628]

17.3.16 Nova submitted that the proposal needs more consideration, "*particularly in our view that the costs of providing n-1 security need to be adequately covered in the TPM*".[629]

17.3.17 Transpower submitted that the "*guidelines are a drafting instruction that draw heavily on the underlying policy decision. We prefer to consider submissions and to allow the policy process to run its course before commenting on the specific details of the guidelines. We have discussed with the Authority the need for a clear delineation between value impacting policy decisions which, where possible, should be made by the Authority and implementation design issues which should be made by Transpower. We consider that the current policy proposals create a number of policy design choices and global parameter choices that may materially affect the allocation of costs between different TPM charges and between the parties affected by each charge. In our view these decisions should be taken by the Authority"*.[630]

17.3.18 Contact's view was consistent to Transpower's view, that "*consideration of the draft Guidelines is premature*".[631] Similarly, Pacific Aluminium considered that it would be "*premature to issue guidelines to Transpower as the Authority needs to do much more work in key areas and consult on this*

626 MRP submission, Appendix A, p. 9

627 MEUG submission, p. 15

628 NZ Steel submission, p. 17

629 Nova submission, p. 10

630 Transpower submission, p. 12

631 Contact submission, p. 36

before it can be confident its guidelines will lead to a TPM that is to the long-term benefit of consumers".[632]

17.3.19 Orion considered there "*may well be detailed technical issues that make implementation of the proposal (as it stands) difficult or expensive. The most important of these should, in our view, be identified and assessed (even at a high level) before detailed design commences. We note the recent difficulties in the area of dispatchable demand".*[633]

17.3.20 Norske Skog agreed that the guidelines were sufficient but noted "*that the Authority has had much to say in different forums about these matters (for instance embedded generation) and it is rather hard to know if the guidelines still apply. Nevertheless we can only submit based on the written proposal, of charging for net injection. We have built embedded generation to reduce our dependence on external sources of electricity and transmission. If it never sees the grid, we don't see why it should incur anything beyond a connection charge*.[634]

17.3.21 TrustPower opposed the draft guidelines and stated that "*TrustPower believes that the Authority has an obligation to determine all the material aspects of design which could have an impact on its and stakeholders analysis of the nature and effect of the TPM Guidelines".*[635]

Too much guidance

17.3.22 Vector considered that the Authority has exceeded its mandate. Vector is *"concerned that the Authority may have gone beyond the requirements of Part 12 of the Electricity Industry Participation Code 2010, which provides that the Authority may issue Guidelines for the development of a TPM (clause 12.83(b)). The Authority has instead developed a pricing methodology."*[636]

17.3.23 Vector explained its interpretation of the Code in detail stating: *"Under the Code, the Authority is given power to make the Guidelines and is not provided with any power to propose a transmission pricing methodology. This function is reserved for Transpower.*

17.3.24 *While there may be debate about the distinction between a guideline for the development of a methodology for transmission pricing and the actual methodology in our opinion the level of detail and prescription proposed in the Authority's proposed Guidelines is such that the Authority has gone beyond the preparation of Guidelines and have sought to determine a methodology.*

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632 Pacific Aluminium submission, p. 22

633 Orion submission, p. 24

634 Norske Skog submission, p. 18

635 TrustPower submission, p. 53

636 Vector submission, p.47-48

17.3.25 *This is illustrated clearly by the statement in the proposed Guidelines, in respect of the interconnection and HVDC charge, that `Transpower should develop a charge consistent with the method set out in Appendix E (SPD method) of this issues paper'. The HVDC charge represents the bulk of the revenue that Transpower would collect in respect of its approved investments and thus the majority of any pricing methodology to be applied by Transpower in recovering its costs.*

17.3.26 *If the proposed Guidelines were made in their current form, Transpower's response to the Guidelines would constitute simply an application of the methodology proposed by the Authority, rather than a proposal for a transmission pricing methodology of Transpower's own making.*

17.3.27 *At its highest the Authority has power to issue guidelines for the development of a TPM. In our view the material released by the Authority is not in the nature of "guidelines", rather the material suggests that the Authority is seeking to prescribe the methodology for the determination of transmission prices. We consider that the Authority has misconstrued its power and would, in making the proposed Guidelines, be acting beyond its powers.*

17.3.28 *The Authority would avoid these outcomes by abandoning its attempt to propose a methodology and, consistent with its statutory powers and functions, propose Guidelines and principles to be followed by Transpower in developing its proposed methodology".*[637]

Suggestions for amendments to the draft guidelines (Question 39)

17.3.29 16 submitters[638] provided suggestions on ways to improve the draft guidelines. Many of those submitters[639] had included their recommendations in their answer to the previous question and referred the Authority to their answer to question 38.

17.3.30 Many submitters, including TrustPower, Nova, and Northpower, suggested that the Authority provide further guidance to Transpower.

17.3.31 TrustPower considered that the Authority *"has an obligation to determine all the material aspects of design which could have an impact on its and stakeholders analysis of the nature and effect of the TPM Guidelines. This includes (but is not limited to):*

(a) *duration of time over which to aggregate benefits and determine charges (i.e. half-hourly, daily, etc.);*

(b) *whether or not negative benefits are taken into account in the aggregation of benefits over time;*

637 Vector submission, p. 47

638 Clearwater Hydro, Powerco, CHH, Meridian, Norske Skog, TrustPower, Vector, Nova, Contact, NZ Steel, Smart Power, MEUG, Pacific Aluminium, MRP, Northpower, Transpower

639 Powerco, Meridian, Transpower, MRP, Contact, TrustPower and MEUG

(c) *whether or not parties will be charged more than their entire spot market rent via the SPD method;*

(d) *appropriate determination of counterfactuals for treatment of like-for-like replacement;*

(e) *appropriate value to be used for situations in which demand is unserved; and*

(f) *whether embedded generation should be charged on a net injection or gross export basis, and whether any de minimus level should apply."*

17.3.32 *With regard to the prioritisation of dynamic efficiency over static (para 7.2.6), TrustPower believes that Transpower will need to quantify any static efficiency losses incurred in the quest to improve dynamic efficiency."*[640]

17.3.33 TrustPower also considered that "*with regard to the residual charge, the issue of whether embedded generators are charged on the basis of gross output or net injection to the transmission grid is not addressed in section 7.*

(a) It should be made clear in the guidelines and in the TPM that embedded generators are treated primarily as negative load, and largely always have been in transmission planning and charging. Any excess embedded generation at peak (i.e. net injection to the grid) should be charged via RCPI as a generator. By the same token, it should be clarified that load is charged on the basis of gross demand in peak periods, rather than demand net of embedded generation.

(b) *The process by which avoided cost of transmission benefits are paid could be streamlined. This could reduce transaction costs between embedded generators and network companies (without opt-out), and avoid embedded generators having to negotiate and transact with retailers in the case that a network company did choose to opt-out. There could therefore be efficiency gains if the process were streamlined."*[641]

17.3.34 Northpower submitted that that "*Regional Coincident Peak Demand (RCPD) in the Upper North Island (UNI) is currently assessed on the basis of the average of the 12 highest regional demands. In contrast, the Lower North Island RCPD is assessed over the average of the 100 highest regional demands"*. Northpower suggested that it "*is now timely to change to the average of 100 highest regional demands for the UNI*". Northpower considered that the guidelines should reflect this.[642]

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640 TrustPower submission, p.53

641 TrustPower submission, p. 53-54

642 Northpower submission, p. 3

17.3.35 Clearwater Hydro submitted that it "*would like to see long term price stability/certainty in the guidelines*"[643].

17.3.36 Vector suggested that less detail should be provided in the draft guidelines, considering that "*the Authority is given power to make the Guidelines and is not provided with any power to propose a transmission pricing methodology. This function is reserved for Transpower*".[644]

Regime needs re-assessing before guidelines can be drafted

17.3.37 Meridian considered that there was "*probably limited value at this stage in providing detailed comments on the draft guidelines unless and until it is known whether the Authority proposes to adopt Meridian's proposals or accept Meridian's comments (or indeed counter proposals put forward by others)"*.[645]

17.3.38 Transpower submitted that given the amount of discussion already generated by the proposal, we cannot help but think that significant changes are likely in consultation. It might therefore be best to leave the guideline drafting till after the design is settled.

17.3.39 CHH[646], MEUG[647], NZ Steel[648] and Smart Power[649] agreed with Transpower that the regime needs re-assessing before guidelines can be drafted. Norske Skog submitted that it hoped that there is no need for any new guidelines.

643 Clearwater submission, p. 12
644 Vector submission, p. 6
645 Meridian submission, p. 69
646 CHH submission, p. 17
647 MEUG submission, p. 17
648 NZ Steel submission, p. 17
649 Smart Power submission, p. 20

18. Draft process for development and approval of TPM (40 to 44)

18.1 Overview: Draft process for development and approval of TPM

18.1.1 The Authority has prepared a draft process for development and approval of the TPM.

18.1.2 The Authority proposes that Transpower present to the Authority how it intends to implement each element of the transmission pricing guidelines. Where relevant, Transpower should demonstrate more than one option for implementing each clause of the guidelines.

18.1.3 The Authority proposed that the process that Transpower should follow in development of the TPM is as follows:

(a) Transpower should prepare a project plan and milestones for development of the detailed methodology, and provide this to the Authority for consideration. The project plan should include the timeframe Transpower proposes for development of the TPM that would achieve the Authority’s objective of having the amended TPM in place in time for the April 2015 pricing year

(b) Transpower should present to the Authority a proposed approach for implementing each element in the transmission pricing guidelines

(c) where relevant, Transpower should demonstrate more than one option for implementation of each clause of the guidelines

(d) Transpower should provide a set of questions regarding the detailed transmission pricing methodology that the Electricity Authority may use in developing consultation material on the transmission pricing methodology proposed by Transpower.

18.1.4 Clauses 12.91 to 12.94 of the Code set out a process for approval of the TPM. The Authority intends to follow this process for approval of the TPM. The Authority intends, however, to allow a consultation period of six weeks on the proposed TPM (which exceeds the 15 days for consultation allowed for in the Code) , subject to the timetable Transpower submits for development of the TPM, so that the new TPM can be implemented in April 2015.

18.1.5 In addition, as the TPM is part of the Code, in order to amend the TPM, the Authority must comply with the Act, in particular section 39. The Authority will provide more information about the steps that it will take, for example the nature and extent of any consultation, in due course.

18.2 What the Authority asked

18.2.1 The Authority sought submitter views on the Authority's proposed process for development of the TPM, asking:

(a) whether submitters agree with the Authority's proposed process that Transpower should follow in developing the TPM, and whether submitters have any suggestions for amendments to the Authority's proposed process? **(Questions 40 and 42)**

(b) whether submitters agree that the Authority does not need to require Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated? **(Question 41)**

(c) whether submitters have comments about the Authority's proposal that Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year? **(Question 43)**

18.2.2 The Authority sought submitter views on the Authority's proposed process for approval of the TPM, asking:

(a) whether submitters agree with the Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower? **(Question 44)**

18.3 Feedback: Draft process for development and approval of TPM

Development

18.3.1 Around half of the submitters agreed in general with the Authority's draft process for development. Common reasons in the submissions for not supporting the Authority's process were that TPM design should be completed before consideration of the process, and that Transpower's operational discretion needed to be reduced.

18.3.2 Powerco suggested that the requirement for review of both the Benchmark Agreement and the Connection Code should be included within the process.

18.3.3 Smart Power requested further information on what the Authority's consultation on the process would cover.

18.3.4 Parties were highly supportive of the Authority's position not to require Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated. Orion pointed out that LCE is not currently subject to regulatory revenue for Transpower.

18.3.5 Many parties considered that it was overly ambitious to have the amended TPM in place for the April 2015 pricing year. Many submitters argued that the timeframe could not realistically be established until a range of matters were addressed and the full implications of the proposal are revealed through detailed design.

18.3.6 CHH and MEUG suggested the Authority take guidance on timeframes from Transpower. Transpower suggested 1 April 2017 was a practical implementation date assuming final pricing guidelines were available by June 2013.

Approval

18.3.7 The Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower was widely supported by most submitters. However Transpower considered that an earlier indication of when industry consultation is likely and the likely duration of the consultation would be beneficial.

18.3.8 Powerco suggested that, given complexity, a consultation period of more than six weeks would be necessary.

Proposed process for development of the TPM (Question 40) and suggested amendments (Question 42)

18.3.9 16 submitters commented on the process for the proposed development of the TPM and some of these submitters provided suggested amendments from improving the process. Out of the 16 submitters, eight[650] supported or partially supported the proposed process while eight submitters[651] did not support the process.

18.3.10 Four submitters considered that the process seemed reasonable[652].

18.3.11 While Clearwater Hydro submitted that the process "*seems to make sense*", it considered that clause 8.2.7 c, whereby Transpower is required to prepare more than one option, was unnecessary[653]

18.3.12 Transpower contended that "*the high level process outlined by the Authority for developing the TPM for submission to the Authority appears logical. The exception is the requirement in 8.2.7(a) for Transpower to include in the project plan a timeframe that would achieve the Authority's target of April 2015.* [654]

650 Clearwater Hydro, CHH, Meridian, Transpower, Orion, Norske Skog, MEUG, Pacific Aluminium

651 Powerco, Pioneer, TrustPower, Vector, Contact, NZ Steel, Smart Power, MRP

652 MEUG, Pacific Aluminium, CHH, Orion

653 Clearwater submission, p 12

654 Transpower submission, p.12

18.3.13 Transpower recommended that the Authority "*should invest time upfront to ensure contentious policy decisions are addressed rather than deferring these to Transpower*".[655]

18.3.14 Transpower is concerned "*that the broader TPM process as currently anticipated will not provide sufficient opportunity to resolve the issues that have been identified with the proposed changes"*. [656]

Complete further work first

18.3.15 Many of the submitters that did not support the proposed process made comments about further work being required before consideration of the draft process.

18.3.16 Powerco stated that it would "*prefer that the Authority undertake further work and consult again before promulgating new transmission pricing guidelines, specifically:*

(a) investigate the relationship between the DPP and the proposed residual charge and how they could be made compatible with each other;

(b) further develop the legal arrangements that would apply, particularly with respect to the physical and notional embedding of generation assets and load control arrangements;

(c) review the former Electricity Commission's decision that distributors and direct connects should be Transpower's legal counterparties at GXPs and subject to transmission charges and identify why the Commission's conclusions no longer apply;

(d) *consult again once this work has been completed*".[657]

18.3.17 Pioneer submitted that the "*Authority's proposed process for Transpower should be reviewed again after the Authority has undertaken the additional consultation we recommend in order to be able to provide more detail in the TPM Guidelines*":[658]

18.3.18 MRP submitted that "*material issues with the Authority's proposal need to be resolved before the guidelines and the process can be developed*".[659]

18.3.19 According to TrustPower, "*the Code shares the responsibility for developing a new TPM between the Authority and Transpower. The Authority is responsible for developing TPM Guidelines, and Transpower for developing the TPM itself. Both entities have responsibilities to ensure the objectives and processes set out in the Act are met."*

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655 Transpower submission, p. 12

656 Transpower submission, p.12

657 Powerco submission, p. 22

658 Pioneer submission, p. 18

659 MRP submission, Appendix A, p. 9

18.3.20 Accordingly, TrustPower considered that Transpower needs to form its own view on the nature and effect of the TPM. TrustPower stated that this Transpower "*assessment should be both qualitative and quantitative. TrustPower expects Transpower to follow administrative law principles, including the requirement for adequate and meaningful consultation on the TPM. TrustPower also expects Transpower to consult with submitters on its own assessment of the extent to which the TPM meets section 15 of the Act.*

18.3.21 *Given the process that Transpower is required to follow, and the level of complexity in the proposal, the 90-day timeframe is unlikely to be sufficient. Transpower is likely to require a considerable extension to this period".*[660]

18.3.22 Contact "*urges the Authority to move forward slowly and ensure it 'brings along' the industry. This is particularly important given the approach taken by the Authority (which is to disregard work of the TPAG and CEO Forum and start with a blank piece of paper to review the TPM) and the considerable upheaval the Proposal would result in*."[661]

18.3.23 NZ Steel suggested that further round(s) on the TPM consultation papers were required. According to NZ Steel, "*April 2015 for implementation is an unnecessary and unachievable date*".[662]

Reduce the level of operational discretion

18.3.24 Meridian submitted above that "*the level of operational discretion provided to Transpower should be minimised, to assist in mitigating disputes over assumptions that will need to be made when operating vSPD or SPD*.

18.3.25 *Meridian considers that those assumptions (refer para. 271) should be determined prior to the guideline being finalised. Workshops would be a useful contributor to resolving some of these issues*".[663]

Requirement for current reviews of the Benchmark Agreement and the Connection Code

18.3.26 Powerco submitted that the process of reviewing the TPM needed to allow "*for the concurrent reviews of the Benchmark Agreement and the Connection Code*, *which will be required to enable retailers to have the status of designated transmission customers, the proposed method for rebating loss and constraint excess to be implemented and the proposed changes to the power factor provisions in the Connection Code to be amended, among other things*". According to Powerco, these "*reviews must be undertaken in accordance with clauses 12.28 to 12.34 of Part 12 the Code (for the Benchmark Agreement) and clauses 12.18 to 12.26 of Part 12 of the Code (for the Connection Code). It is possible that it may prove necessary to*

[660] TrustPower submission, p. 54

[661] Contact submission, p. 37

[662] NZ Steel submission, p. 17

[663] Meridian submission, p. 69

develop a new separate Benchmark Agreement for retailers to enable them to be counterparties to Transpower. Alternatively, amendments to the Code could achieve the new relationships envisaged between Transpower and retailers, but the Code amendments required would be substantial and consequential amendments would still be required to the Benchmark Agreement. The updated Benchmark Agreement (or Agreements), the revised Connection Code and any required amendments to the Electricity Industry Participation Code must come into force on the same date as the new TPM if all the regulatory arrangements relating to transmission pricing are to work effectively as a whole".[664]

More information

18.3.27 Smart Power requested more information on process, submitting that its support for the process depended on what the consultation by the Authority will cover. Smart Power submitted that "*it is very important that consultation is held again once the detail of how Transpower will put it in place is available. That consultation should not be 'filtered' by the Authority and should contain all options put forward by Transpower*".[665]

Requirement for Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated (Question 41)

18.3.28 Responses were received by fourteen parties on question 41. Of these submitters, 12[666] agreed with the Authority's statement while two[667] parties disagreed.

18.3.29 Parties supportive of the statement were of the general view that if revenue were not regulated by either the Commerce Commission or the Electricity Authority, it was not a regulatory concern as to how costs related to that revenue were allocated.

18.3.30 Clearwater Hydro submitted that "*unregulated is unregulated*"[668], while Meridian considered that it was "*not aware of any reason to depart from this position*."[669]

18.3.31 Powerco contended that it agreed with the statement "*because investment approval is now the responsibility of the Commerce Commission and*

664 Powerco submission, p. 22

665 Smart Power submission, p. 20

666 Clearwater Hydro, Powerco, CHH, Meridian, Transpower, Orion, Norske Skog, TrustPower, Vector, NZ Steel, MEUG, and Pacific Aluminium

667 MRP and Smart Power

668 Clearwater submission, p. 12

669 Meridian submission, p. 70

Transpower is subject to individual price-quality path regulation under Part 4 of the Commerce Act 1986."[670]

18.3.32 TrustPower advised "*that the Commerce Commission regime provides establishes clear rules for the separation of regulated and non-regulated income and the apportionment of overheads between each revenue segment. As this proposal only concerns the allocation of costs of the regulated income, TrustPower does not consider that the Authority needs to make any requirements of Transpower in relation to the determination or allocation of its non-regulated revenue"*.[671]Orion suggested that "*this would seem to be outside the purview of the Authority under the Code?*"[672]

18.3.33 Orion noted that "*LCE is not currently, as we understand it, regulatory revenue for Transpower*".[673]

18.3.34 Smart Power's submission suggested a qualified disagreement stating "*no doubt the Authority is legally correct however we believe this should be included feedback on it may be useful for the Commerce Commission and if it is of interest to stakeholders then they should be given that information*".[674] While NZ Steel agreed with the Authority's statement, it considered that, if there was a perceived issue, "*the non regulated costs should be reviewed for inclusion*".[675]

18.3.35 MRP submitted that "*material issues with the Authority's proposal need to be resolved before the guidelines and the process can be developed*".[676]

Whether Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year (Question 43)

18.3.36 16[677] submitters commented on whether Transpower should propose a timeframe to the Authority of having the amended TPM in place in time for the April 2015 pricing year. Almost all of these submitters considered that the timeframe could not be met, or that meeting the timeframe was unlikely.

18.3.37 Orion suggested the timeframe was reasonably although stated that "*it must be acknowledged that the time frame could slip as the full implications of the proposal are revealed through detailed design*".[678] TrustPower stated that it "*is not possible to ascertain whether the April 2015 timeframe is realistic.*

[670] Powerco submission, p.22

[671] TrustPower submission, p. 54

[672] Orion submission, p. 24

[673] Orion submission, p.24

[674] Smart Power submission, p. 21

[675] NZ Steel submission, p. 17

[676] MRP submission, Appendix A, p. 9

[677] Clearwater Hydro, Powerco, CHH, Meridian, Pioneer, Transpower, Orion, Norske Skog, TrustPower, Vector, Contact, Smart Power, MEUG, NZ Steel, Pacific Aluminium, MRP

[678] Orion submission, p. 25

Given the range of matters still to be addressed, TrustPower suspects it is not".[679]

18.3.38 NZ Steel advised that "*further round(s) on the TPM consultation papers are required. April 2015 for implementation is an unnecessary and unachievable date*".[680]

18.3.39 Contact argued that the Authority should acknowledge that the date is too optimistic.[681]

18.3.40 Powerco submitted that "*it is already March 2013, the reviews of the Benchmark Agreement and Connection Code that need to be completed in tandem with the development of the new TPM have not year (sic) commenced, a great deal of further practical and legal work needs to be done, and past experience has shown that the processes in the Code that need to be completed require considerable time. For Transpower to apply a new TPM to calculate charges for the 2015/16 year, the new methodology would need to be approved by August 2014 at the latest. We would suggest that, from this starting point, this goal is not feasible*".[682]

18.3.41 Vector considers it "*premature to consider the appropriate process for Transpower until it has been determined:*

- *(a) whether a change in TPM will be adopted; and*
- (b) *which pricing methodology which best meet the Authority's statutory objective*".[683]

18.3.42 Meridian "*suspects that an April 2015 implementation date is increasingly unlikely*. However, Meridian also stated that "*the sooner a more efficient TPM is in place, the sooner the identified efficiencies will start to accrue for the long term benefit of consumers. It is therefore important to continue to progress this with a degree of urgency".*[684]

The Authority to be advised by Transpower on timeframes

18.3.43 CHH and MEUG suggested that "*Transpower advises the EA of:*

- *(a) The cost to achieve a 1st April 2015 deadline; and*
- *(b) The alternative cost if implementation were delayed to 1st April 2016 or later... (and)*

679 TrustPower submission, p. 55
680 NZ Steel submission, p. 17
681 Contact submission, p. 37
682 Powerco submission, p. 23
683 Vector submission, p. 48
684 Meridian submission, p. 70

18.3.44 *If there was a material decrease in implementation costs with a delay, then the EA could weigh the savings in implementation costs against forgoing benefits in deciding optimal timing*".[685][686]

18.3.45 Transpower submitted that "from the time the Authority issues guidelines:

(a) *a period of 12 months should be allowed for developing the pricing guidelines into full pricing rules. The process will be technically challenging, will require some critical design decisions, and customer engagement to ensure a robust product*

(b) *a further period of 12 months of parallel operation (including providing customers with 'shadow' invoices) should be allowed. The pricing systems and processes will produce complex outputs (for example, a small retailer may have more than 3000 charge components per month). Parallel operation will confirm the systems are operating correctly, while allowing customers to understand how their charges change over a year*.

18.3.46 Transpower considered 1 April 2017 is the practical implementation date assuming final pricing guidelines are available by June this year.Transpower further advised that this is an "*initial estimate and can be refined when there is a clear understanding of the final proposal*".[687]

The Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower (Question 44)

18.3.47 12[688] submitters commented on the proposal to decide on the consultation period after the proposed TPM has been received from Transpower.

18.3.48 There was widespread submitters support the Authority's proposal although Transpower disagreed with the Authority's proposal.

18.3.49 Transpower contended that it thinks that it "*would be beneficial to the industry if the Authority provides an earlier indication of when industry consultation is likely and the duration of that consultation".* According to Transpower *"this will assist participants with resource planning but would not preclude extension or deferral if new information comes to light".*[689]

18.3.50 Powerco agreed with the proposal and added that "*given the complexity of the proposals under consideration, a consultation period of more than six weeks will be required".*[690]

685 CHH submission, p. 18

686 MEUG submission, p. 17

687 Transpower submission, p. 13

688 Powerco, CHH, Meridian, Pioneer, Transpower, Norske Skog, TrustPower, Vector, NZ Steel, Smart Power, MEUG, Pacific Aluminium

689 Transpower submission, p. 13

690 Powerco submission, p. 23

18.3.51 Pioneer agreed, although contended that *“a 'deadline' of having the new TPM implemented for April 2015 should remain flexible to ensure appropriate time for consultation and successful implementation*”.[691]

18.3.52 Contact requested the Authority “*provide enough consultation opportunities to enable greater consensus to be achieved and ensure that the issues of most contention can be addressed early*”.[692]

691 Pioneer submission, p. 19

692 Contact submission, p.38